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July 31, 2023

Rules Coordinator
Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, Texas 78711-2967

Via Electronic Filing

RE: **Comments regarding Public Comment Hearing on the proposed amendments to Chapter 5, relating to Carbon Dioxide (CO_2)**

To the Rules Coordinator:

I am a local geologist concerned with the impact of carbon sequestration in the Coastal Bend area. I work for a local oil and gas exploration company and have overseen our RRC compliance. We've recently been attending multiple talks from the DOE and local universities regarding CO_2 capture and storage. The following comments and questions regarding the proposed amendments to Chapter 5 have been made based on my years of experience in the Oil and Gas industry.

Sincerely,

Payton Campbell

Geologist

<u>REMARKS and COMMENTS</u>

1. **As Chapter 5 is written, it is clear the director would have too much power to control all aspects of the Class VI decision making. How does the RRC perceive how the chain of Class VI application information is disseminated to the director? What is the engineering, petrophysical, geochemical, geological, and geophysical checks and balances that would ensure public safety and freshwater protections?**
2. **Since this is a new class of wells, why wouldn't the RRC form a Class VI RRC division to include certified petroleum engineers and Texas Board Professional Geoscientist (TBPG) geologist, petrophysicist, geochemical and geophysicists on a team to evaluate each aspect of the application and operations?**
3. **How will penalties be assessed by the EPA and RRC for non-compliance of the permit? What happens if trespassing of the CO2 plume and/or pressure front extends beyond the AOR? What about wells that are not plugged or breached by CO2 injection? Are penalties assessed and what mitigation costs are included in the financial considerations?**
4. **Explain how the modeling of the AOR, CO2 plume, and pressure front are calculated. Will rules for modeling be standardized or will the RRC rely on the operator's information provided?**
5. **What happens to the facility supplying the CO2 in the event of an injection well shutdown? Will the facility providing the CO2 stream be allowed to vent the CO2? When does the EPA step in to address the unrestricted flow of CO2 into the atmosphere?**
6. **In the event of non-compliance for wellbore integrity, will testing of the issues become more frequent until the issue is resolved? What about if AOR limit is exceeded, will modeling and testing be required at least semiannually to determine the short and long-term effects?**
7. **What are the requirements for the third-party delegate financial evaluator? Will there be sufficient liability insurance for private or public property damages? Chapter 5 states that additional personnel for the RRC will not be needed. How is this justified when a third-party delegate is hired to evaluate the financial requirements of the permit?**
8. **Carbon sequestration and protecting groundwater is essential. What assurances will the RRC enact for the protection of the public's health and safety?**
9. **Will the Bureau of Economic Geology recommendation of 1000' of shale seal above the injection zone be required for Class VI wells? What about 3-D seismic requirements to limit transmissive faulting breach?**

10. **Will stratigraphic test wells within the AOR be required to have the same casing requirements as an injection well? What happens if the CO2 plume encounters the test well and degradation to the cement and casing occurs?**
11. **Will stratigraphic test wells requirement to have logging, coring and pressure testing be standardized for all new wells drilled within the AOR? Why or why not?**
12. **Reporting of the status of the well integrity, equipment and AOR is critical to adherence to the EPA rules. Will penalties and fines be levied against operators for non-compliance?**
13. **Will the retention period of the records be made public and why not for 10 years instead of the amended 3 years? If non-compliance or well integrity issues occur why not longer?**
14. **Loss of internal mechanical integrity could result in a multitude of issues for the injection well. This could also increase risk for groundwater and public safety. Instead of allowing continuing injection at the unrestricted option of the director, shouldn't a team be assembled to determine the risks before continuing injection?**
15. **Regarding reporting requirements of any physical alterations, would it not be safer for the public and freshwater supply to have operator report occurrence immediately? What are the monetary penalties for non-compliance?**

Comments below are by page number highlighted in yellow followed by the line number corresponding to response comments.

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19 micro business should have gross receipts numbering $2m. Should this be revised to include AI or any corporation financially able to secure development and dissolution of facilities?

Texas Government Code, §2006.002, relating to Adoption of Rules with Adverse Economic Effect, requires that, before adopting a rule that may have an adverse economic effect on small businesses or micro-businesses, a state agency prepare an economic impact statement and a regulatory flexibility analysis. The economic impact statement must estimate the number of small businesses subject to the proposed rule and project the economic impact of the rule on small businesses. A regulatory flexibility analysis must include the agency's consideration of alternative methods of achieving the purpose of the proposed rule. If consistent with the health, safety, and environmental and economic welfare of the state, the analysis must consider the use of regulatory methods that will accomplish the objectives of applicable rules while minimizing adverse impacts on small businesses. Government Code §2006.001(2) defines "small business" as a legal entity, including a corporation, partnership, or sole proprietorship, that is formed for the purpose of making a profit; is independently owned and operated; and has fewer than 100 employees or less than $6 million in annual gross receipts. A "micro-business" is defined as a legal entity, including a corporation, partnership, or sole proprietorship, that is formed for the purpose of making a profit; is independently owned and operated; and has no more than 20 employees.

****THIS IS WRONG. SHOULD INCREASE RRC PERSONNEL TO APPROVE APPLICATIONS AND REVIEW FORMS AND NONCOMPLIANCE. THIS IS AN UNPROVEN TECHNOLOGY AND UNTIL ASSURANCES CAN BE MADE THAT IT IS SAFE FOR PUBLIC HEALTH AND WATER MORE QUALIFIED RRC PERSONNEL ARE NEEDED.**

During the first five years that the rules would be in full effect, the proposed amendments adopted pursuant to House Bill 1284 (87th Legislature, Regular Session, 2021) could create a new government program because the proposed amendments will allow the Commission to apply for state primacy such that the state may administer a Class VI UIC program. However, EPA must first approve the Commission's application for primacy. The proposed amendments would not create a new regulation because the Commission is adopting requirements that are included in existing federal regulations. Similarly, because federal regulations are in place to govern Class VI UIC activities, the proposed amendments also do not increase responsibility for persons under the Commission's jurisdiction and would not increase or decrease the number of individuals subject to the rules. If the Commission's primacy application is approved, the state will administer the Class VI UIC program rather than EPA. Therefore, the proposed amendments could create an increase in fees paid to the Commission. The Commission does not propose amending the fees contained in §5.205 but may receive those fees if it is approved to administer the Class VI UIC program. Finally, the proposed amendments would not affect the state's economy and would not require a change in employee positions.

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Commission jurisdiction to ensure standards comply with federal requirements of EPA set up special interest-bearing funds consisting of penalties. This alone will require more personnel.

wells; Texas Water Code, Chapter 27, Subchapter C-1, which gives the Commission jurisdiction over the geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir; Texas Health and Safety Code §382.502, which allows the Commission to adopt by rule standards for the location, construction, maintenance, monitoring, and operation of a carbon dioxide repository and requires the Commission to ensure standards comply with federal requirements issued by the EPA; and Texas Water Code, Chapter 120, which establishes the Anthropogenic Carbon Dioxide Storage Trust Fund, a special interest-bearing fund in the state treasury, to consist of fees collected by the Commission and penalties imposed under Texas Water Code, Chapter 27, Subchapter C-1, and to be used by the Commission for only certain specified activities associated with geologic storage facilities and associated anthropogenic carbon dioxide injection wells.

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Line 6 must include injectivity testing and 3D seismic.

(47) Stratigraphic test well--An exploratory well drilled for the purpose of gathering information in connection with a proposed carbon dioxide geologic storage project, including formation testing to obtain information on the chemical and physical characteristics of the injection zones and confining zones. Such testing may include injectivity testing.

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Line 33 what if the plume interacts with stratigraphic test well and degradation of cement and casing occurs? Shouldn't there be more requirements for casing and cement in a known stratigraphic test well?

(h) An operator shall apply for a permit to drill (Form W-1) prior to drilling a stratigraphic test well, notify the UIC Section of the application, and submit a completion report (Form W-2/G-1) once the well is completed. If the operator plans to convert the stratigraphic test well to a Class VI injection well, the well construction shall meet all of the requirements of this subchapter for a Class VI injection well. Any stratigraphic test well drilled for exploratory purposes only shall be governed by the provisions of Commission rules in Chapter 3 of this title (relating to Oil and Gas Division) applicable to the drilling, safety, casing, production, abandoning, and plugging of wells.

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Line 10 What about if records indicate noncompliance and/or corrective action needed for an injection well? Then shouldn't AOR be delineated with more frequency, perhaps each year, until compliance achieved and AOR model determined to be stable?

(B) for the AOR, a description of:

(i) the minimum fixed frequency, not to exceed five years, [~~subject to the annual certification pursuant to §5.206(f) of this title (relating to Permit Standards)~~] at which the applicant proposes to re-evaluate the AOR during the life of the geologic storage facility;

(ii) how monitoring and operational data will be used to re-evaluate the AOR; and

(iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and

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Line 20 we would suggest setting up a Class VI division consisting of certified petroleum engineers and a Texas Board of Professional Geoscientists that reports to Commission & Director instead of the Director having sole discretion. There's confusion in allowing the director to require further cores when once the injection well is cased then cores cannot be taken. Typically log analysis, core analysis, and formation fluid sample information is taken from an open hole and casing the well occurs immediately after.

(B) The operator must take [~~submit analyses of~~] whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone. The director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The operator must submit to the director a detailed report prepared by a log analyst that includes well log analyses (including well logs), core analyses, and formation fluid sample information. The director may require the operator to core other formations in the borehole.

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Line 25 we agree with the timing and monitoring regarding reports sent to commission, however the operator should be penalized monetarily for non-compliance of this provision.

(C) after initiation of injection, the performance on a quarterly [~~semi-annual~~] basis of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring semi-annually [~~annually~~]. Corrosion monitoring may be accomplished by:

(i) analyzing coupons of the well construction materials in contact with the CO_2 stream;

(ii) routing the CO_2 stream through a loop constructed with the materials used in the well and inspecting the materials in the loop; or

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Lines 21,25 &26 regarding the director making all decisions we suggest setting up Class VI division consisting of certified petroleum engineers and a Texas Board of Professional Geoscientists that reports to Commission & Director.

(F) a demonstration of external mechanical integrity pursuant to subsection (h)(2) of this section at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log pursuant to requirements in subsection (h)(2) of this section at a frequency established in the testing and monitoring plan;

(G) [~~(F)~~] a [~~A~~] pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and

(H) [~~(G)~~] additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.

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Line 3 regarding retention period should be 10 years or life of the project as well as the records being open to the public.

(i) calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and

(ii) the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment of the injection well. The director may require the operator to submit the records to the director at the conclusion of the retention period.

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Line 1 Disagree with director allowing operator to continue injection unless at least monthly monitoring of the well, AOR, and movement of the injection fluid are in place.

(4) The director may allow the operator of a well which lacks internal mechanical integrity to continue or resume injection if the operator has made a satisfactory demonstration that there is no movement of fluid into or between USDWs.

Line 4 & 5 should still be in place and not stricken.

[~~(3) The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.~~]

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Line 16 regarding permit records retention should be 10 years after the last monitor well and facility closed and then made available for public use.

(1) The permittee shall retain records of all monitoring information, including the following:

(A) calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and

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Line 13 regarding reporting requirement planned changes should have a definitive time frame instead of as soon as possible verbiage.

(M) Reporting requirements.

(i) Planned changes. The permittee shall give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility.

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Lines 1 &2 should include monetary penalties for non-compliance.

eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:

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Lines 11-26 should require all records to be sent to the RRC and available for public use.

(e) Record retention.

(1) The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.

(2) The operator must retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) of this title until 10 years after storage facility closure. The operator shall submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.

(3) The operator must retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) of this title, including wellhead pressure records, metering records, and integrity test results, and modeling inputs and data used to support AOR calculations for at least 10 years after the data is collected.

(4) The operator must retain well plugging reports, post-injection storage facility care data, including data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure.

(5) The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.