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WAYNE CHRISTIAN, *COMMISSIONER*
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RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

MEMORANDUM

June 13, 2023		
Approved	**Denied**	**Abstain**
DS CC		
DS WC		
DS JW		

TO: Chairman Christi Craddick
Commissioner Wayne Christian
Commissioner Jim Wright

FROM: Haley Cochran, Assistant General Counsel

THROUGH: Alexander C. Schoch, General Counsel

DATE: June 13, 2023

SUBJECT: Proposed Amendments to Chapter 5, relating to Carbon Dioxide

Attached is Staff's recommendation to publish proposed amendments to 16 Texas Administrative Code Chapter 5, relating to Carbon Dioxide ($CO2$). Staff proposes these amendments to ensure that the rules are as stringent as the requirements of the U.S. Environmental Protection Agency (the "EPA") to support the Commission's application to EPA for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

The Commission adopted initial regulations to implement the Class VI UIC program effective December 20, 2010, and amended those regulations in 2022 to reflect changes in the Texas statutes and to ensure that the state's program meets the minimum federal requirements for Class VI UIC wells. The State submitted to EPA its official application for primacy on December 19, 2022. Included in that application was a crosswalk comparison of the state and federal requirements. In March 2023, EPA provided comments to the crosswalk comparison and recommended rule amendments in a few areas. These proposed amendments are intended to respond to EPA's recommendations.

Staff requests the Commission's approval to publish the proposed amendments in the *Texas Register* for public comment. If approved at conference on June 13, the proposal should appear in the June 30th issue of the *Texas Register*. The proposal and an online comment form would also be made available on the Commission's website, giving interested persons more than two additional weeks to review and submit comments to the Commission.

Cc: Wei Wang, Executive Director
Danny Sorrells, Deputy Executive Director and Director of the Oil and Gas Division
Leslie Savage, Chief Geologist, Oil and Gas Division

The Railroad Commission of Texas (the "Commission") proposes amendments to §5.102 (relating to Definitions) in Subchapter A; and in Subchapter B proposes amendments to §§5.201 and 5.203 - 5.207 (relating to Applicability and Compliance; Application Requirements; Notice of Permit Actions and Public Comment Period; Fees, Financial Responsibility, and Financial Assurance; Permit Standards; and Reporting and Record-Keeping, respectively).

The Commission proposes the amendments to ensure that the rules are as stringent as the requirements of the U.S. Environmental Protection Agency ("EPA") to support the Commission's application to EPA for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

EPA protects underground sources of drinking water (USDWs) by regulating the injection of fluids underground for storage or disposal. The Safe Drinking Water Act (SDWA) and the UIC program provide the primary regulatory framework. From the early 1980s until 2010, EPA regulated five classes of wells according to the type of fluid injected, the depth of injection, and the potential to endanger USDWs. Historically, most states have sought and been granted primacy over one or more classes of wells. For example, most states have primacy over Class II wells, in which fluids are injected for natural gas and oil production, hydrocarbons storage, and enhanced recovery of oil and gas.

In 2010, EPA promulgated rules creating a sixth well class (Class VI) specifically to regulate the injection of carbon dioxide ("CO_2") into deep subsurface rock formations. EPA established minimum technical criteria for permitting, site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well-plugging, post-injection site care, and site closure requirements.

Under the SDWA, EPA may delegate its authority to implement and enforce the UIC program to states upon application. If EPA approves a state's application, the state assumes primary enforcement authority (i.e., primacy) over a class or classes of wells. Until a state receives primacy, EPA directly implements the UIC program through its regional offices.

The State of Texas has established a statutory framework for projects involving the capture, injection, sequestration or geologic storage of anthropogenic carbon dioxide. The statutes require the state to pursue primacy for the Class VI UIC program. After almost a decade of little interest, interest in carbon capture and geologic sequestration or storage has increased over the past several years prompting the Commission to resume efforts to gain primacy for the Class VI UIC program.

The Commission adopted initial regulations to implement the Class VI UIC program effective December 20, 2010, and amended those regulations in 2021 to reflect changes in the Texas statutes and to ensure that the state's program meets the minimum federal requirements for Class VI UIC wells. The State submitted to EPA its official application for primacy of the Class VI UIC program on December 19,

2022. Included in that application was a cross-walk comparison (i.e., a table comparing state and federal requirements). In March of 2023, EPA provided comments to the cross-walk comparison and recommended rule amendments in a few areas. These proposed amendments respond to EPA's recommendations.

Proposed amendments to §5.102

The Commission proposes to amend §5.102(2) to amend the definition of "Anthropogenic carbon dioxide (CO_2)" to reflect that the term includes all carbon dioxide that has been captured from, or would otherwise have been released into, the atmosphere. EPA expressed concern that the regulations referred only to "anthropogenic carbon dioxide." The proposed change would clarify that the regulations apply to carbon dioxide resulting from direct air capture technologies. A corresponding change is also proposed in the definition of "carbon dioxide (CO_2) stream" in §5.102(7).

The Commission proposes to amend the definition of "anthropogenic CO_2 injection well" in §5.102(3) and the definition of "geologic storage" in §5.102(28) to clarify that the regulations apply to the various phases of carbon dioxide (gaseous, liquid, or supercritical) for consistency with the federal Class VI UIC regulations.

The Commission proposes to add new paragraph (20) in §5.102 to define EPA as the United States Environmental Protection Agency.

The Commission proposes amendments to the definition of "good faith claim" in §5.102(30) to ensure the rule acknowledges that an operator and the owner of the pore space may use various mechanisms to grant the legal right to access and use the pore space.

The Commission proposes to amend §5.102 to add a new paragraph (47) to define "stratigraphic test well." The Commission also proposes to add new §5.102(51) to define "UIC" as Underground Injection Control.

Proposed amendments to §5.201

The Commission proposes to amend §5.201 to add a new subsection (h) regarding requirements for stratigraphic test wells.

Proposed Amendments to §5.203

The Commission proposes amendments in §5.203. First, the Commission proposes amendments to §5.203(a)(1)(B)(iii) to describe federal signatories to permit applications and required reports should a federal agency submit a Class VI UIC permit application consistent with 40 CFR §144.32(a)(3)(ii). EPA indicated that such an application is possible.

The Commission proposes to amend §5.203(a)(2)(C) to replace the word "relevant" with "required" consistent with the federal requirement at 40 CFR §144.31(e)(6) that an applicant list all permits or construction approvals received or applied for under the Hazardous Waste Management program under the Resource Conservation and Recovery Act (RCRA), the UIC program under SDWA, the National Pollutant Discharge Elimination System (NPDES) program under the Clean Water Act, the Prevention of Significant Deterioration (PSD) program under the Clean Air Act, the Nonattainment program under the Clean Air Act, the National Emissions Standards for Hazardous Pollutants (NESHAP) preconstruction approval under the Clean Air Act, the ocean dumping permits under the Marine Protection Research and Sanctuaries Act, dredge and fill permits under section 404 of Clean Water Act, and other relevant environmental permits, including State permits.

The Commission proposes to amend §5.203(a)(2) to add new subparagraph (E) to require that the application for a Class VI UIC well indicate whether the geologic storage project is located on Indian lands consistent with the federal requirements. The Commission also proposes to amend §5.203(a)(2) to add new subparagraph (F) to require that the application include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the area of review (AOR) of the geologic storage project based on the map showing the injection well and the AOR consistent with 40 CFR §146.82(a)(2).

The Commission proposes to amend §5.203(b)(2)(A) to require that the applicant show within the AOR on the map the number or name and location of stratigraphic boreholes consistent with 40 CFR §146.82(a)(2).

The Commission proposes to amend §5.203(d)(1)(C), which requires the applicant to demonstrate that abandoned wells in the AOR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs. The proposed amendment requires a demonstration that the materials used are compatible with the carbon dioxide stream consistent with 40 CFR §146.84(c)(3).

The Commission proposes to amend §5.203(d)(2)(B) to clarify that the AOR must be reevaluated at a fixed frequency not to exceed five years throughout the life of the geologic storage facility consistent with the federal requirements at 40 CFR §§146.84(b)(2)(i) and 146.84(e).

The Commission proposes to amend §5.203(e)(1)(B)(v) to clarify that at least one long string casing must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages consistent with 40 CFR §146.86(b)(3).

The Commission proposes to amend §5.203(e)(2)(D) to require an applicant to provide to the Commission in the application the external pressure, internal pressure, and axial loading consistent with the requirements in 40 CFR §146.86(b)(1)(ii).

The Commission proposes to amend §5.203(e)(4) to clarify that the applicant must include a description of the stimulation fluids in its description of the proposed well stimulation program if the well is to be stimulated consistent with 40 CFR §146.82(a)(9).

The Commission proposes to amend §5.203(f) to amend the title of the subsection to clarify that the plan for logging, sampling, and testing applies to logging, sampling and testing before injection. There are two separate authorizations associated with Class VI wells: (1) authorization to drill the well and perform logging, sampling and testing, and (2) authorization to inject. The applicant must submit a plan for logging, sampling, and testing of each injection well after the Commission has granted authority to drill a well but prior to authorization to inject carbon dioxide.

The Commission also proposes to amend §5.203(f)(3)(B) to clarify that the operator must take whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone and 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 amendment further clarifies that 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 director may require the operator to core other formations in the borehole. The amendments to §5.203(f) are consistent with 40 CFR §146.87(b).

The Commission proposes to amend §5.203(j)(2)(C), which relates to the requirement for a plan for monitoring, sampling, and testing after initiation of operation. The proposed amendments state that the plan must include a requirement for the performance of corrosion monitoring of the well materials on a quarterly, rather than semi-annual, basis. The amendments change the reporting requirements such that monitoring results must be reported on a semi-annual, rather than annual, basis consistent with 40 CFR §146.90(c).

The Commission proposes to amend §5.203(j)(2) to add new subparagraph (F). The proposed new subparagraph requires that the plan include a demonstration of external mechanical integrity at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log at a frequency established in the testing and monitoring plan consistent with 40 CFR §146.90(e). The Commission proposes to redesignate §5.203(j)(2)(F) as §5.203(j)(2)(G) and §5.203(j)(2)(G) as §5.203(j)(2)(H).

The Commission proposes to amend §5.203(m)(8)(D) to include examples of existing information (e.g., at Class I, Class II, or Class V experimental technology well sites). This amendment is consistent with the federal requirements at 40 CFR §146.93(c)(2)(iv).

Proposed Amendments to §5.204

The Commission proposes to amend §5.204 to require that the Commission give notice of a draft permit or a public hearing to any State, Tribe, or Territory any portion of which is within the AOR of the

Class VI project consistent with 40 CFR §146.82(b). The Commission proposes to redesignate (xi) as (xii) and (xii) as (xiii).

The Commission proposes to amend §5.204(b)(5) to clarify that, upon making a final permit decision, the director shall issue a response to comments, which must specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change, and briefly describe and respond to all significant comments on the draft permit raised during the public comment period or during any hearing. Furthermore, the Commission must post the response to comments on the Commission's internet website. These amendments are consistent with 40 CFR § 124.17.

Proposed Amendments to §5.205

The Commission proposes amendments to §5.205(c). Amendments proposed in §5.205(c) state that the director shall consider and approve the applicant's demonstration of financial responsibility for all the phases of the geologic sequestration project, including the post-injection storage facility care and closure phase and the plugging phase, prior to issuance of a geologic storage injection well permit.

The Commission proposes to amend §5.205(c)(2)(A)(i) and (C)(i) to clarify that the written estimate of the highest likely dollar amount necessary to perform post-injection site closure (PISC) monitoring and closure of the facility must include plugging of all injection wells and that the amount of financial assurance required to be filed under this subchapter must include plugging of all injection wells consistent with 40 CFR 146.85(a)(2)(ii).

The Commission proposes to amend §5.205(c)(2)(C)(i) to clarify that the amount of financial assurance required to be filed under this subchapter must include plugging, and that the cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.

The Commission proposes to amend §5.205(c)(2)(D) to add new (iii) to clarify that the qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable. In addition, an operator must provide that their financial instrument may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.

Furthermore, operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

The Commission also proposes new §5.205(c)(2)(D)(iii)(III) to state that cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect if on or before the date of expiration: the director deems the facility abandoned; the permit is terminated or revoked or a new permit is denied; closure is ordered by the director or a U.S. district court or other court of competent jurisdiction; the operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid. These amendments are consistent with 40 CFR §146.85(a)(4).

The Commission proposes to amend §5.205(c)(2)(E) to require that, during the active life of the geologic storage project, the operator adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with subsection (c)(2)(C)(i) of §5.205 and provide this adjustment to the director. The operator must also provide to the director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and remedial response plan.

The Commission proposes to amend §5.205(c)(2)(F) to clarify that the director must approve annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the PISC and closure plan. In addition, during the active life of the geologic storage project, the operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the PISC and closure plan, and the emergency and response plan, if the change in the plan increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of the financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified in §5.205(c)(2)(E). Furthermore, the operator must provide to the director, within 60 days of notification by the director (rather than upon request) an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and PISC and closure, and emergency and remedial response. These amendments are consistent with the federal requirements in 40 CFR §146.85(c)(1).

The Commission proposes to amend §5.205(c)(2) to add new subparagraph (G) to require that, whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director. These amendments are consistent with the federal requirements in 40 CFR §146.85(e).

The Commission proposes to amend §5.205(c)(2) to add new subparagraph (H) to state that the requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit. Proposed new subparagraph (H)(i) clarifies that the operator must maintain financial responsibility until the director receives and approves the completed post-injection storge facility care and closure plan and approves storage facility closure. Proposed new subparagraph (H)(ii) states that the operator may be released from a financial instrument in the following circumstances: (1) the operator has completed the phase of the geologic storage project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the geologic storage project, if required; or (2) the operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the operator from the previous financial instrument. These amendments are consistent with the requirements at 40 CFR §146.85(b)(2).

The Commission proposes to amend §5.205(c) to add new paragraph (5) to clarify that the operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration consistent with 40 CFR §146.85(a)(5)(ii).

Proposed Amendments to §5.206

The Commission proposes to amend §5.206(a) to divide the subsection into two paragraphs. New paragraph (2) clarifies that a permit will include a condition that states that the permit may be modified, revoked and reissued, or terminated for cause and that the filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition. These amendments are consistent with the requirements in 40 CFR §144.51(f).

The Commission proposes to amend §5.206(b) to add new paragraph (4) to state that the director may issue a permit under this subchapter if the applicant demonstrates and the director finds that the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons. This amendment is consistent with the federal requirements in 40 CFR §144.12(a).

The Commission proposes to amend §5.206(c)(2) to clarify that the well completion information must be filed on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log. This amendment is consistent with the federal requirements in 40 CFR §146.82(c)(5). The Commission Form W-2, and all other Commission forms, can be found by clicking on the "Forms" tab on the Commission's website.

The Commission proposes to amend §5.206(d)(1) to clarify the information that the operator must submit and the director must consider before granting approval for the operation of a Class VI injection well. Proposed new subparagraph (A) includes the existing language. Proposed new subparagraph (B) clarifies that, prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, certain information detailed in proposed new (i) through (x). Proposed new (i) lists the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by subsection (d)(1)(B)(ii), (iii), (iv), (v), (vi), (vii), (viii) and (x).

Proposed new §5.206(d)(1)(B)(ii) requires the operator to submit and the director to consider any relevant updates, based on data obtained during logging and testing of the well and the formation as required by §5.203(f), to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations submitted to satisfy the requirements of subsection (d)(1)(B)(iii), (iv), (v), (vi), (vii), and (x).

Proposed new §5.206(d)(1)(B)(iii) requires the operator to submit and the director to consider information on the compatibility of the CO_2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well.

Proposed new §5.206(d)(1)(B)(iv) requires the operator to submit and the director to consider the results of the formation testing program required by §5.203(f). Proposed new §5.206(d)(1)(B)(v) requires the operator to submit and the director to consider the final injection well construction procedures that meet the requirements of §5.203(e).

Proposed new §5.206(d)(1)(B)(vi) requires the operator to submit and the director to consider the status of corrective action on wells in the AOR. Proposed new §5.206(d)(1)(B)(vii) requires the operator to submit and the director to consider all available logging and testing program data on the well required by §5.203(f).

Proposed new §5.206(d)(1)(B)(viii)-(x) require the operator to submit and the director to consider: a demonstration of mechanical integrity pursuant to §5.203(h); any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m), which are necessary to address new information collected during logging and testing of the well and the formation as required by §5.206, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m), which are necessary to address new information collected during the logging and testing of the well and the formation as required by §5.206; and any other information requested by the director.

These amendments are consistent with the federal requirements in 40 CFR §146.82(c) and distinguish between the requirements of the initial permit application and the requirements to update any permit application/permit elements prior to granting approval to inject.

The Commission proposes to amend §5.206(e) to add new paragraph (5). The new paragraph states that samples and measurements taken for the purpose of monitoring must be representative of the monitored activity and that the permittee must retain records of all monitoring information, including the following: (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 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. Proposed new §5.206(e)(5)(C) requires that records of monitoring information include: (i) the date, exact place, and time of sampling or measurements; (ii) the individuals who performed the sampling or measurements; (iii) the dates analyses were performed; (iv) the individuals who performed the analyses; (v) the analytical techniques or methods used; and (vi) the results of such analyses. Proposed new paragraph (5)(D) requires that operators of Class VI wells retain records as specified in Subchapter B of Chapter 5.

The Commission also proposes to amend §5.206(f) to revise paragraph (2) add a permit condition that clarifies that the operator must establish mechanical integrity prior to commencing injection. The Commission proposes to add new paragraph (3) to add a permit condition that states that, if the director determines that the injection well lacks mechanical integrity, the director shall give written notice of the director's determination to the operator. Unless the director requires immediate cessation, the operator shall cease injection into the well within 48 hours of receipt of the director's determination. The director may allow plugging of the well pursuant or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The operator may resume injection upon written notification of the director's determination that the operator has demonstrated the well has mechanical integrity.

The Commission proposes to add new paragraph (4) in §5.206(f) to add a permit condition that states that 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. Existing paragraph (4) is renumbered (5).

These amendments ensure that the rules meet the minimum standards of the federal requirements in 40 CFR §144.51.

The Commission also proposes to amend §5.206(g) to clarify that the AOR must be reevaluated at a minimum frequency not to exceed five years as specified in the approved AOR and corrective action plan. In addition, the AOR must be reevaluated whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator.

The Commission proposes to amend §5.206(g)(4) to clarify that any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements in §5.202.

The Commission proposes to add new paragraph (g)(5) to require that the operator retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.

The Commission proposes to amend §5.206(h)(1) to clarify that the emergency and remedial response plan and the demonstration of financial responsibility must account for the AOR delineated as specified in §5.203(d)(1)(A) - (C) or the most recently evaluated AOR delineated under subsection (g) of §5.206, regardless of whether or not corrective action in the AOR is phased consistent with 40 CFR §146.84(f).

The Commission proposes to amend §5.206(h)(3) to clarify that, if any water quality monitoring of an USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including plugging of the injection well) as are necessary to prevent such movement. This amendment is consistent with the federal requirements in 40 CFR §144.12(b).

The Commission proposes to amend §5.206(k)(5) require the operator to submit a plugging record (Form W-3) as required by §3.14 of this title (relating to Plugging) after the director has authorized storage facility closure and plugged all wells in accordance with the approved plugging plan. This amendment is consistent with the federal requirements in 40 CFR §144.52(a)(7)(i).

The Commission proposes to amend §5.206(m) to clarify that the operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, in addition to other records and that the operator must 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. This amendment is consistent with the federal requirements in 40 CFR §146.91(f)(1).

The Commission proposes to amend §5.206(m) to add requirements to make the rules consistent with the federal requirements at 40 CFR §144.51(j). New paragraph (1) adds a permit condition that the permittee must 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 the permit, and records of all data used to complete the application for the 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 (B) the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures. The director may require the operator to submit the records to the director at the conclusion of the retention period.

Proposed new paragraph (2) adds a permit condition that records of monitoring information shall include: (A) the date, exact place, and time of sampling or measurements; (B) the individuals who performed the sampling or measurements; (C) the dates analyses were performed; (D) the individuals who performed the analyses; (E) the analytical techniques or methods used; and (F) the results of such analyses.

Proposed new paragraph (3) specifies records that the operator must retain for 10 years following storage facility closure. The operator must retain records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the PISC period. The operator must 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.

The Commission proposes to amend §5.206(o)(1) to clarify that permits issued under Subchapter B of Chapter 5 shall be issued for the operating life of the facility and the post-injection storage facility care period. The director shall review each permit at least once every five years to determine whether it should be modified, revoked and reissued, or terminated.

The Commission proposes to amend §5.206(o)(2)(J) to clarify that a condition shall be included in a Class VI permit to require that if the time necessary for completion of any interim requirement is more than one year and is not readily divisible into stages for completion, the permit shall specify interim dates for the submission of reports of progress toward completion of the interim requirements and indicate a projected completion date. These amendments are consistent with federal requirements in 40 CFR §144.53(a)(2)(ii).

The Commission proposes to amend §5.206(o)(2) to add new subparagraph (K) to add a permit condition that states that the permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

The Commission proposes to add new §5.206(o)(2)(L) to require a permit condition that all applications, reports, or information be signed and certified.

The Commission also proposes to add new §5.206(o)(2)(M) to add the following permit conditions: (i) the permittee shall give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility; (ii) the permittee shall give advance notice to the director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements; (iii) the permit is not transferable to any person except after notice to and approval by the director. The director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA; (iv) monitoring results shall be reported at the intervals specified elsewhere in the permit; (v) reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of the permit shall be submitted no later than 30 days following each schedule date; and (vi) the permittee shall report any noncompliance which may endanger health or the environment including any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW, and any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Proposed new §5.206(o)(2)(M)(vi) requires the information to be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

Proposed new §5.206(o)(2)(N) adds a requirement that where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the director, it shall promptly submit such facts or information.

Proposed new §5.206(o)(2)(O) requires the permittee to report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of paragraph (2), and §5.207(a)(2)(A), at the time monitoring reports are submitted. The reports shall contain any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW, and any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

Proposed new §5.206(o)(2)(P) requires that new permits, and to the extent allowed under §5.202 modified or revoked and reissued permits, incorporate each of the applicable requirements referenced in this section. An applicable requirement is a State statutory or regulatory requirement that takes effect prior to final administrative disposition of the permit. An applicable requirement is also any requirement that takes effect prior to the modification or revocation and reissuance of a permit, to the extent allowed in §5.202.

Proposed new §5.206(o)(2)(Q) states that in addition to conditions required in all permits, the director shall establish conditions in permits as required on a case-by-case basis, to provide for and assure compliance with all applicable requirements of the Safe Drinking Water Act and 40 CFR Parts 144, 145, 146 and 124. These amendments are consistent with the federal requirements in 40 CFR §144.52.

Proposed Amendments to §5.207

The Commission proposes to amend §5.207(a)(2)(A) to require the operator to report certain operating information to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The Commission proposes to amend §5.207(a)(2)(A) to add new clause (i), which is existing language revised to delete repetitive language. Proposed new clause (ii) would require reporting of any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW. Proposed new clause (iii) requires reporting of any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs. Proposed new clause (iv) requires the reporting of any triggering of a shut-off system (i.e., down-hole or at the surface). Proposed new clause (v) requires the reporting of any failure to maintain mechanical integrity. These amendments are consistent with the federal requirements in 40 CFR §146.91(c)(2).

The Commission proposes to reorganize §5.207(a)(2)(D) and add new (E) to clarify requirements for annual reports and updates.

The Commission proposes to amend §5.207(e) to require that the operator must retain all testing and monitoring data collected under §5.203 for the permit application for at least 10 years following storage facility closure. The operator must also retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) until 10 years after storage facility closure. At the end of the retention period, the operator shall submit the records to the director. Third, 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.

Proposed new §5.207(e)(4) requires that the operator retain for 10 years following storage facility closure 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). Proposed new §5.207(e)(5) contains existing language. Proposed new §5.207(e)(6) and (7) clarify that the director has authority to require the operator to retain any records required in Subchapter B for longer than 10 years after storage facility closure and to require the operator to submit the records to the director at the conclusion of the retention period. These amendments are consistent with 40 CFR §146.91(f).

Leslie Savage, Chief Geologist, Oil and Gas Division, has determined that for each year of the first five years that the amendments will be in effect, there will be no additional economic costs for persons required to comply with the proposed amendments. The federal regulations governing Class VI wells may create costs for persons required to comply. However, persons required to comply with the federal requirements must do so regardless of whether the requirements are adopted in Commission rules because if the Commission is not approved to enforce the Class VI program, EPA will enforce the same requirements. The proposed amendments to Commission rules do not create any additional economic costs for persons required to comply.

Ms. Savage has determined that for each year of the first five years that the amendments will be in effect, the public benefit will be the Commission's evaluation of information regarding geologic storage of anthropogenic carbon dioxide, and consideration of other factors related to the prevention of pollution of surface and subsurface waters of the state and promotion of safety in accordance with Texas Natural Resources Code, §85.042 and §91.101. Achieving meaningful reductions in CO_2 emissions while preserving the benefits of our energy-intensive economy cannot be accomplished without significant deployment of carbon sequestration.

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.

Entities that perform activities under the jurisdiction of the Commission are not required to report to the Commission their number of employees or their annual gross receipts, which are elements of the definitions of "micro-business" and "small business" in Texas Government Code, §2006.001; therefore, the Commission has no factual bases for determining whether any persons who drill and complete wells under the jurisdiction of the Railroad Commission will be classified as small businesses or micro-businesses, as those terms are defined. The North American Industrial Classification System (NAICS) sets forth categories of business types. Operators of oil and gas wells fall within the category for crude petroleum and natural gas extraction. This category is listed on the Texas Comptroller of Public Accounts website page entitled "HB 3430 Reporting Requirements-Determining Potential Effects on Small Businesses" as business type 2111 (Oil & Gas Extraction), for which there are listed 2,784 companies in Texas. This source further indicates that 2,582 companies (92.7%) are small businesses or micro-businesses as defined in Texas Government Code, §2006.001.

Based on the information available to the Commission regarding oil and gas operators and the complexity of the Class VI UIC requirements, Ms. Savage has concluded that, of the businesses that could be affected by the proposed amendments, it is unlikely that many would be classified as small businesses or micro-businesses, as those terms are defined in Texas Government Code, §2006.001. Furthermore, the bulk of the proposed amendments are necessary to ensure that the Commission's regulations meet the requirements of the U.S. Environmental Protection Agency (EPA) to enable EPA to approve state primacy for the Class VI UIC program. If the state does not have primacy for the Class VI program, EPA is the permitting agency. Therefore, the costs imposed by the proposed amendments would be comparable to the costs imposed by the federal regulations.

The Commission has also determined that the proposed amendments will not affect a local economy. Therefore, the Commission has not prepared a local employment impact statement pursuant to Texas Government Code §2001.022.

The Commission has determined that the amendments do not meet the statutory definition of a major environmental rule as set forth in Texas Government Code, §2001.0225(a); therefore, a regulatory analysis conducted pursuant to that section is not required.

The Commission reviewed the proposed amendments and found that they are neither identified in Coastal Coordination Act Implementation Rules, 31 TAC §29.11(b)(4), nor would they affect any action or authorization identified in Coastal Coordination Act Implementation Rules, 31 TAC §29.11(a)(3). Therefore, the proposed amendments are not subject to the Texas Coastal Management Program.

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.

As part of the public comment period, the Commission will hold a virtual public hearing to receive comments on the proposed amendments to Chapter 5.

The hearing will be structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the virtual hearing; however, Commission staff will be available after the meeting to discuss the proposal. Depending on the number of persons wishing to speak, the Commission may impose a time limit so that everyone who wishes to make a public comment will have the opportunity to do so.

The hearing will be conducted remotely using an internet meeting service. Individuals who plan to participate in the hearing and provide oral comments and/or want their participation on record must register in accordance with instructions provided on the Commission's website. Information regarding the public hearing will be posted on the Commission's website at least 10 business days in advance of the hearing, which will occur within the comment period. Instructions for participating in the hearing will be sent to those who register for the hearing. Individuals who do not wish to provide oral comments but would like to view the hearing may do so. A link to the webcast will be added on the Commission's website.

Any individual with a disability who plans to participate in the hearing and who requires auxiliary aids or services should notify the Commission as far in advance as possible so that appropriate arrangements can be made. Requests may be made to the Human Resources Department of the Railroad Commission of Texas by mail at P.O. Box 12967, Austin, Texas 78711-2967; by telephone at 512-463-6981 or TDD No. 512-463-7284; by e-mail at ADA@rrc.texas.gov; or in person at 1701 North Congress Avenue, Suite 12-110, Austin, Texas.

Comments on the proposed amendments may be submitted to Rules Coordinator, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967; online at www.rrc.texas.gov/general-counsel/rules/comment-form-for-proposed-rulemakings; or by electronic mail to rulescoordinator@rrc.texas.gov. The Commission will accept comments until 5:00 p.m. on Monday, July 31, 2023. The Commission finds that this comment period is reasonable because the proposal and an online comment form will be available on the Commission's website more than two weeks prior to Texas Register publication of the proposal, giving interested persons additional time to review, analyze, draft, and submit comments. The Commission cannot guarantee that comments submitted after the deadline will be considered. For further information, call Ms. Savage at (512) 463-7308. The status of Commission rulemakings in progress is available at www.rrc.texas.gov/general-counsel/rules/proposed-rules. Once received, all comments are posted on the Commission's website at https://rrc.texas.gov/general-counsel/rules/proposed-rules/. If you submit a comment and do not see the comment posted at this link within three business days of submittal, please call the Office of General Counsel at (512) 463-7149. The Commission has safeguards to prevent emailed comments from getting lost; however, your operating system's or email server's settings may delay or prevent receipt.

The Commission proposes the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code, Chapter 91, Subchapter R, relating to authorization for multiple or alternative uses of 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.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052; Texas Natural Resources Code, Chapter 91, Subchapter R; Texas Health and Safety Code §382.502; and Texas Water Code, Chapters 27 and 120.

Cross reference to statute: Texas Natural Resources Code, Chapters 81 and 91, Texas Health and Safety Code, Chapter 382, and Texas Water Code, Chapters 27 and 120.

§5.102 Definitions.

The following terms, when used in Subchapter B of this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of activity sought to be permitted has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Anthropogenic carbon dioxide (CO_2)--

(A) CO_2 that <u>has been captured from or</u> would otherwise have been released into the atmosphere that has been:

(i) separated from any other fluid stream; or

(ii) captured from an emissions source, including:

(I) an advanced clean energy project as defined by Health and Safety Code, §382.003, or another type of electric generation facility; or

(II) an industrial source of emissions; and

(iii) any incidental associated substance derived from the source material for, or from the process of capturing, CO_2 described by clause (i) of this subparagraph; and

(iv) any substance added to CO_2 described by clause (i) of this subparagraph to enable or improve the process of injecting the CO_2; and

(B) does not include naturally occurring CO_2 that is produced, acquired, recaptured, recycled, and reinjected as part of enhanced recovery operations.

(3) Anthropogenic CO_2 injection well--An injection well used to inject or transmit gaseous, liquid, or supercritical anthropogenic CO_2 into a reservoir.

(4) Aquifer--A geologic formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

(5) Area of review (AOR)--The subsurface three-dimensional extent of the CO_2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and the surface area above that delineated region.

(6) Carbon dioxide (CO_2) plume--The underground extent, in three dimensions, of an injected CO_2 stream.

(7) Carbon dioxide (CO_2) stream--CO_2 that has been captured from an emission source or the atmosphere, incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. The term does not include any CO_2 stream that meets the definition of a hazardous waste under 40 CFR Part 261.

(8) Casing--A pipe or tubing of appropriate material, of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent loss of drilling mud into porous ground, or to prevent water, gas, or other fluid from entering or leaving the hole.

(9) Cementing--The operation whereby a cement slurry is pumped into a drilled hole and/or forced behind the casing.

(10) Class VI well--Any well used to inject anthropogenic CO_2 specifically for the purpose of the long-term containment of a gaseous, liquid, or supercritical CO_2 in subsurface geologic formations.

(11) Code of Federal Regulations (CFR)--The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the federal government.

(12) Commission--A quorum of the members of the Railroad Commission of Texas convening as a body in open meeting.

(13) Confining zone--A geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone or zones that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone or zones that acts as a barrier to fluid movement.

(14) Corrective action--Methods to assure that wells within the area of review do not serve as conduits for the movement of fluids into or between underground sources of drinking water, including the use of corrosion resistant materials, where appropriate.

(15) Delegate--The person authorized by the director to take action on behalf of the Railroad Commission of Texas under this chapter.

(16) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(17) Division--The Oil and Gas Division of the Railroad Commission of Texas.

(18) Draft permit--A document prepared indicating the director's tentative decision to issue or deny, modify, revoke and reissue, terminate, or reissue a permit. A notice of intent to terminate a permit, and a notice of intent to deny a permit are types of "draft permits." A denial of a request for modification, revocation and reissuance, or termination is not a draft permit.

(19) Enhanced recovery operation--Using any process to displace hydrocarbons from a reservoir other than by primary recovery, including using any physical, chemical, thermal, or biological process and any co-production project. This term does not include pressure maintenance or disposal projects.

(20) EPA--The United States Environmental Protection Agency.

(21) [~~(20)~~] Exempted aquifer--An aquifer or its portion that meets the criteria in the definition of underground source of drinking water but which has been exempted according to the procedures in 40 CFR §144.7.

(22) [~~(21)~~] Facility closure--The point at which the operator of a geologic storage facility is released from post-injection storage facility care responsibilities.

(23) [~~(22)~~] Flow rate--The volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

(24) [~~(23)~~] Fluid--Any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state.

(25) [~~(24)~~] Formation--A body of consolidated or unconsolidated rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

(26) [~~(25)~~] Formation fluid--Fluid present in a formation under natural conditions.

(27) [~~(26)~~] Fracture pressure--The pressure that, if applied to a subsurface formation, would cause that formation to physically fracture.

(28) [~~(27)~~] Geologic storage--The long-term containment of gaseous, liquid, or supercritical anthropogenic CO_2 in subsurface geologic formations.

(29) [~~(28)~~] Geologic storage facility or storage facility--The underground geologic formation, underground equipment, injection wells, and surface buildings and equipment used or to be used for the geologic storage of anthropogenic CO_2 and all surface and subsurface rights and appurtenances necessary to the operation of a facility for the geologic storage of anthropogenic CO_2. The term includes the subsurface three-dimensional extent of the CO_2 plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region, and any reasonable and necessary areal buffer and subsurface monitoring zones. The term does not include a pipeline used to transport CO_2 from the facility at which the CO_2 is captured to the geologic storage facility. The storage of CO_2 incidental to or as part of enhanced recovery operations does not in itself automatically render a facility a geologic storage facility.

(30) [~~(29)~~] Good faith claim--A factually supported claim based on a recognized legal theory to a perpetual property interest [~~continuing possessory right~~] in pore space to be used for geologic storage of carbon dioxide, such as:

(A) [~~evidence of~~] a currently valid lease evidenced by a recorded memorandum of lease;

(B) a recorded perpetual easement; or

(C) a recorded deed conveying a fee interest in the pore space.

(31) [~~(30)~~] Injection zone--A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic storage facility.

(32) [~~(31)~~] Injection well--A well into which fluids are injected.

(33) [~~(32)~~] Interested person--Any person who expresses an interest in an application, permit, or Class VI UIC well.

(34) [~~(33)~~] Limited English-speaking household--A household in which all members 14 years and older have at least some difficulty with English.

(35) [~~(34)~~] Lithology--The description of rocks on the basis of their physical and chemical characteristics.

(36) [~~(35)~~] Mechanical integrity--

(A) An anthropogenic CO_2 injection well has mechanical integrity if:

(i) there is no significant leak in the casing, tubing, or packer; and

(ii) there is no significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection well bore as a result of operation of the injection well.

(B) The Commission will consider any deviations during testing that cannot be explained by the margin of error for the test used to determine mechanical integrity, or other factors, such as temperature fluctuations, to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection wellbore.

(37) [~~(36)~~] Monitoring well--A well either completed or re-completed to observe subsurface phenomena, including the presence of anthropogenic CO_2, pressure fluctuations, fluid levels and flow, temperature, and/or in situ water chemistry.

(38) [~~(37)~~] Offshore--The area in the Gulf of Mexico seaward of the coast that is within three marine leagues of the coast.

(39) [~~(38)~~] Operator--A person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the rules and regulations regarding the permitting, physical operation, closure, and post-closure care of a geologic storage facility, or such person's authorized representative.

(40) [~~(39)~~] Packer--A device lowered into a well to produce a fluid-tight seal.

(41) [~~(40)~~] Permit--An authorization, license, or equivalent control document issued by the Commission to implement the requirements of this chapter.

(42) [~~(41)~~] Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(43) [~~(42)~~] Plugging--The act or process of stopping the flow of water, oil or gas into or out of a formation through a borehole or well penetrating that formation.

(44) [~~(43)~~] Post-injection facility care--Monitoring and other actions (including corrective action) needed following cessation of injection to assure that underground sources of drinking water are not endangered and that the anthropogenic CO_2 remains confined to the permitted injection interval.

(45) [~~(44)~~] Pressure front--The zone of elevated pressure that is created by the injection of the CO_2 stream into the subsurface where there is a pressure differential sufficient to cause movement of the CO_2 stream or formation fluids from the injection zone into an underground source of drinking water.

(46) [~~(45)~~] Reservoir--A natural or artificially created subsurface stratum, formation, aquifer, cavity, void, or coal seam.

(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.

(48) [~~(46)~~] Stratum (or strata)--A single sedimentary bed or layer, regardless of thickness, that consists of generally the same kind of rock material.

(49) [~~(47)~~] Surface casing--The first string of well casing to be installed in the well.

(50) [~~(48)~~] Transmissive fault or fracture--A fault or fracture that has sufficient permeability and vertical extent to allow fluids to move beyond the confining zone.

(51) UIC--Underground injection control.

(52) [~~(49)~~] Underground source of drinking water (USDW)--An aquifer or its portion which is not an exempt aquifer as defined in 40 CFR §146.4 and which:

(A) supplies any public water system; or

(B) contains a sufficient quantity of ground water to supply a public water system; and

(i) currently supplies drinking water for human consumption; or

(ii) contains fewer than 10,000 mg/l total dissolved solids.

(53) [~~(50)~~] Well injection--The subsurface emplacement of fluids through a well.

(54) [~~(51)~~] Well stimulation--Any of several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for fluid to move more readily into the formation including, but not limited to, surging, jetting, blasting, acidizing, and hydraulic fracturing.

(55) [~~(52)~~] Workover--An operation in which a down-hole component of a well is repaired or the engineering design of the well is changed. Workovers include operations such as sidetracking, the addition of perforations within the permitted injection interval, and the addition of liners or patches. For the purposes of this chapter, workovers do not include well stimulation operations.

§5.201 Applicability and Compliance.

(a) Scope of jurisdiction. This subchapter applies to the geologic storage and associated injection of anthropogenic CO_2 in this state, both onshore and offshore.

(b) Injection of CO_2 for enhanced recovery.

(1) This subchapter does not apply to the injection of fluid through the use of an injection well regulated under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) for the

primary purpose of enhanced recovery operations from which there is reasonable expectation of more than insignificant future production volumes of oil, gas, or geothermal energy and operating pressures are no higher than reasonably necessary to produce such volumes or rates. However, the operator of an enhanced recovery project may propose to also permit the enhanced recovery project as a CO_2 geologic storage facility simultaneously.

(2) If the director determines that an injection well that is permitted for the injection of CO_2 for the purpose of enhanced recovery regulated under §3.46 of this title should be regulated under this subchapter because the injection well is no longer being used for the primary purpose of enhanced recovery operations or there is an increased risk to USDWs, the director must notify the operator of such determination and allow the operator at least 30 days to respond to the determination and to file an application under this subchapter or cease operation of the well. In determining if there is an increased risk to USDWs, the director shall consider the following factors:

(A) increase in reservoir pressure within the injection zone;

(B) increase in CO_2 injection rates;

(C) decrease in reservoir production rates;

(D) distance between the injection zone and USDWs;

(E) suitability of the enhanced oil or gas recovery AOR delineation;

(F) quality of abandoned well plugs within the AOR;

(G) the storage operator's plan for recovery of CO_2 at the cessation of injection;

(H) the source and properties of injected CO_2; and

(I) any additional site-specific factors as determined by the director.

(3) This subchapter does not preclude an enhanced oil recovery project operator from opting into a regulatory program that provides carbon credit for anthropogenic CO_2 sequestered through the enhanced recovery project.

(c) Injection of acid gas. This subchapter does not apply to the disposal of acid gas generated from oil and gas activities from leases, units, fields, or a gas processing facility. Injection of acid gas that contains CO_2 and that was generated as part of oil and gas processing may continue to be permitted as a Class II injection well. The potential need to transition a well from Class II to Class VI shall be based on the increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk. In determining if there is an increased risk to USDWs, the director shall consider the following factors:

(1) the reservoir pressure within the injection zone;

(2) the quantity of acid gas being disposed of;

(3) the distance between the injection zone and USDWs;

(4) the suitability of the disposed waste AOR delineation;

(5) the quality of abandoned well plugs within the AOR;

(6) the source and properties of injected acid gas; and

(7) any additional site-specific factors as determined by the director.

(d) This subchapter applies to a well that is authorized as or converted to an anthropogenic CO_2 injection well for geologic storage (a Class VI injection well). This subchapter applies regardless of whether the well was initially completed for the purpose of injection and geologic storage of anthropogenic CO_2 or was initially completed for another purpose and is converted to the purpose of injection and geologic storage of anthropogenic CO_2, except that the Commission may not issue a permit under this subchapter for the conversion of a previously plugged and abandoned Class I injection well, including any associated waste plume, to a Class VI injection well.

(e) Expansion of aquifer exemption. The areal extent of an aquifer exemption for a Class II enhanced recovery well may be expanded for the exclusive purpose of Class VI injection for geologic storage if the aquifer does not currently serve as a source of drinking water; and the total dissolved solids content is more than 3,000 milligrams per liter (mg/l) and less than 10,000 mg/l; and it is not reasonably expected to supply a public water system in accordance with 40 CFR §146.4. An operator seeking such an expansion shall submit, concurrent with the permit application, a supplemental report that complies with 40 CFR §144.7(d). The Commission adopts 40 CFR §144.7 and §146.4 by reference, effective September 20, 2022.

(f) Injection depth waiver. An operator may seek a waiver from the Class VI injection depth requirements for geologic storage to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment. An operator seeking a waiver of the requirement to inject below the lowermost USDW shall submit, concurrent with the permit application or a permit amendment application, a supplemental report that complies with 40 CFR §146.95. The Commission adopts 40 CFR §146.95 by reference, effective September 20, 2022.

(g) This subchapter does not apply to the injection of any CO_2 stream that meets the definition of a hazardous waste under 40 CFR Part 261.

(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.

(i) [~~(h)~~] If a provision of this subchapter conflicts with any provision or term of a Commission order or permit, the provision of such order or permit controls.

(j) [~~(i)~~] The operator of a geologic storage facility must comply with the requirements of this subchapter as well as with all other applicable Commission rules and orders, including the requirements of Chapter 8 of this title (relating to Pipeline Safety Regulations) for pipelines and associated facilities.

§5.203 Application Requirements.

(a) General.

(1) Form and filing; signatories; certification.

(A) Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality.

(B) Signatories to permit applications. An applicant must ensure that the application is executed by a party having knowledge of the facts entered on the form and included in the required attachments. All permit applications shall be signed as specified in this subparagraph:

(i) For a corporation, the permit application shall be signed by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation, or the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(ii) For a partnership or sole proprietorship, the permit application shall be signed by a general partner or the proprietor, respectively.

(iii) For a municipality, State, Federal, or other public agency, the permit application shall be signed by either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a federal agency includes the chief executive officer of the agency or a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

(C) Certification. Any person signing a permit application or permit amendment application shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(2) General information.

(A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.

(B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(C) The application must include a listing of all required [~~relevant~~] permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO_2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.

(E) The application must indicate whether the geologic storage project is located on Indian lands.

(F) The application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR.

(3) Application completeness. The Commission shall not issue a permit before receiving a complete application. A permit application is complete when the director determines that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the director.

(4) Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.

(5) If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this subchapter and must affix the appropriate seal on the resulting reports of such evaluations.

(b) Surface map and information. Only information of public record is required to be included on this map.

(1) The applicant must file with the director a surface map delineating the proposed location of any injection wells and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR.

(2) The applicant must show within the AOR on the map the number or name and the location of:

(A) all known artificial penetrations through the confining zone, including stratigraphic boreholes, injection wells, producing wells, inactive wells, plugged wells, or dry holes;

(B) the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and

(C) other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.

(3) The applicant must identify on the map any known or suspected faults expressed at the surface.

(c) Geologic, geochemical, and hydrologic information.

(1) The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations.

(2) The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:

(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;

(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;

(C) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;

(D) the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;

(E) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;

(F) a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and

(G) baseline geochemical data for subsurface formations that will be used for monitoring purposes, including all formations containing USDWs within the AOR.

(d) AOR and corrective action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application.

(1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.

(A) Delineation of AOR.

(i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO_2 stream, the physical properties of the formation into which the CO_2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO_2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods:

(I) five years after initiation of injection;

(II) from initiation of injection to the end of the injection period proposed by the applicant; and

(III) from initiation of injection until the movement of the CO_2 plume and associated pressure front stabilizes.

(ii) The applicant must use a computational model that:

(I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone;

(II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;

(III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;

(IV) considers the physical and chemical properties of injected and formation fluids; and

(V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.

(iii) The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.

(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.

(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO_2 stream. Corrective action may be phased.

(2) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information:

(A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(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

(C) a corrective action plan that describes:

(i) how the corrective action will be conducted;

(ii) how corrective action will be adjusted if there are changes in the AOR;

(iii) if a phased corrective action is planned, how the phasing will be determined; and

(iv) how site access will be secured for future corrective action.

(e) Injection well construction.

(1) Criteria for construction of anthropogenic CO_2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO_2 injection wells that an applicant must include in an application.

(A) General. The operator of a geologic storage facility must ensure that all anthropogenic CO_2 injection wells are constructed and completed in a manner that will:

(i) prevent the movement of injected CO_2 or displaced formation fluids into any unauthorized zones or into any areas where they could endanger USDWs;

(ii) allow the use of appropriate testing devices and workover tools; and

(iii) allow continuous monitoring of the annulus space between the injection tubing and long string casing.

(B) Casing and cementing of anthropogenic CO_2 injection wells.

(i) The operator must ensure that injection wells are cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.

(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director.

(iii) Surface casing must extend through the base of the lowermost USDW above the injection zone and must be cemented to the surface.

(iv) Circulation of cement may be accomplished by staging. The director may approve an alternative method of cementing in cases where the cement cannot be circulated to the surface, provided the applicant can demonstrate by using logs that the cement does not allow fluid movement between the casing and the well bore.

(v) At least one long string casing, using a sufficient number of centralizers, must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).

(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.

(vii) The director may exempt existing Class II wells that have been associated with injection of CO_2 for the purpose of enhanced recovery, Class V experimental technology wells, and stratigraphic test wells from provisions of these casing and cementing requirements if the applicant demonstrates that the well construction meets the general performance criteria in subparagraph (A) of this paragraph. A converted well must meet all other requirements under this section. The demonstration must include the following:

(I) as-built schematics and construction procedures to demonstrate that repermitting is appropriate;

(II) recent or newly conducted well-log information and mechanical integrity test results;

(III) a demonstration that any needed remedial actions have been performed;

(IV) a demonstration that the well was engineered and constructed to meet the requirements of subparagraph (A) of this paragraph and ensure protection of USDWs;

(V) a demonstration that cement placement and materials are appropriate for CO_2 injection for geologic storage;

(VI) a demonstration that the well has, and is able to maintain, internal and external mechanical integrity over the life of the project; and

(VII) the results of any additional testing of the well to support a demonstration of suitability for geologic storage.

(C) Special equipment.

(i) Tubing and packer. All injection wells must inject fluids through tubing set on a packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.

(ii) Pressure observation valve. The wellhead of each injection well must be equipped with a pressure observation valve on the tubing and each annulus of the well.

(2) Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:

(A) depth to the injection zone;

(B) hole size;

(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);

(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and [~~and/or~~] mass of the CO_2 stream to be injected;

(E) type of packer and packer setting depth;

(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO_2 stream and formation fluids;

(G) down-hole temperatures and pressures;

(H) lithology of injection and confining zones;

(I) type or grade of cement and additives;

(J) chemical composition and temperature of the CO_2 stream; and

(K) schematic drawings of the surface and subsurface construction details.

(3) Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.

(4) Well stimulation plan. The applicant must submit[~~, as applicable,~~] a description of the proposed well stimulation program, including a description of the stimulation fluids, and a determination that well stimulation will not compromise containment.

(f) Plan for logging, sampling, and testing of injection wells [~~after permitting but~~] before injection. The applicant must submit a plan for logging, sampling, and testing of each injection well [~~after permitting but~~] prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO_2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.

(1) Logs and surveys of newly drilled and completed injection wells.

(A) During the drilling of any hole that is constructed by drilling a pilot hole that is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.

(C) After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.

(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.

(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.

(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.

(B) The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO_2.

(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.

(3) Sampling.

(A) The operator must record and submit the formation fluid temperature, pH, and conductivity, the reservoir pressure, and the static fluid level of the injection zone.

(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.

(g) Compatibility determination. Based on the results of the formation testing program required by subsection (f) of this section, the applicant must submit a determination of the compatibility of the CO_2 stream with:

(1) the materials to be used to construct the well;

(2) fluids in the injection zone; and

(3) minerals in both the injection and the confining zone.

(h) Mechanical integrity testing.

(1) Criteria. This paragraph establishes the criteria for the mechanical integrity testing plan for anthropogenic CO_2 injection wells that an applicant must include in an application.

(A) Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.

(B) Before beginning injection operations and at least once every five years thereafter, the operator must demonstrate internal mechanical integrity for each injection well by pressure testing the tubing-casing annulus.

(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.

(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).

(E) The operator must test injection wells after any workover that disturbs the seal between the tubing, packer, and casing in a manner that verifies internal mechanical integrity of the tubing and long string casing.

(F) An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.

(2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:

(A) a pressure test with liquid or inert gas;

(B) a tracer survey such as oxygen-activation logging;

(C) a temperature or noise log;

(D) a casing inspection log; and/or

(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.

(i) Operating information.

(1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:

(A) the average and maximum daily injection rates, temperature, and volumes and/or mass of the CO_2 stream;

(B) the average and maximum surface injection pressure;

(C) the sources of the CO_2 stream and the volume and/or mass of CO_2 from each source; and

(D) an analysis of the chemical and physical characteristics of the CO_2 stream prior to injection.

(2) Maximum injection pressure. The director will approve a maximum injection pressure limit that:

(A) considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;

(B) with a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and

(C) in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.

(j) Plan for monitoring, sampling, and testing after initiation of operation.

(1) The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.

(2) The plan must include the following:

(A) the analysis of the CO_2 stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;

(B) the installation and use of continuous recording devices to monitor injection pressure, rate, temperature, and volume and/or mass, and the pressure on the annulus between the tubing and the long string casing, except during workovers;

(C) after initiation of injection, the performance on a <u>quarterly</u> [~~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 <u>semi-annually</u> [~~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

(iii) using an alternative method, materials, or time period approved by the director;

(D) monitoring of geochemical and geophysical changes, including:

(i) periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone;

(ii) periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO_2 through the confining zone into that monitored formation;

(iii) the location and number of monitoring wells justified on the basis of the AOR, injection rate and volume, geology, and the presence of artificial penetrations and other factors specific to the geologic storage facility; and

(iv) the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;

(E) tracking the extent of the CO_2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools;

(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.

(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that penetrate the base of usable quality water that includes the following:

(1) a proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:

(A) the type and number of plugs to be used;

(B) the placement of each plug, including the elevation of the top and bottom of each plug;

(C) the type, grade, and quantity of material to be used in plugging and information to demonstrate that the material is compatible with the CO_2 stream; and

(D) the method of placement of the plugs;

(2) proposals for activities to be undertaken prior to plugging an injection well, specifically:

(A) flushing each injection well with a buffer fluid;

(B) performing tests or measures to determine bottomhole reservoir pressure;

(C) performing final tests to assess mechanical integrity; and

(D) ensuring that the material to be used in plugging must be compatible with the CO_2 stream and the formation fluids;

(3) a proposal for giving notice of intent to plug monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that:

(A) the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and

(B) the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;

(4) a plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;

(5) a plan for plugging all monitoring wells that do not penetrate the base of usable quality water in accordance with 16 TAC Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers); and

(6) a plan for certifying that all monitoring wells that do not penetrate the base of usable quality water will be plugged in accordance with 16 TAC Chapter 76.

(l) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:

(1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;

(2) describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods;

(3) includes a safety plan that includes:

(A) emergency response procedures;

(B) provisions to provide security against unauthorized activity;

(C) CO_2 release detection and prevention measures;

(D) instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;

(E) procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;

(F) provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO_2,

(G) the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and

(H) if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and

(4) includes a description of the training and testing that will be provided to each employee at the storage facility on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility. The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. Emergency measures specific to the contractor's work must be explained in the contractor safety meeting. Training schedules, training dates, and course outlines must be provided to Commission personnel upon request for the purpose of Commission review to determine compliance with this paragraph.

(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:

(1) a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must be based on significant, site-specific data and information, including

all data and information collected pursuant subsections (b)-(d) of this section and §5.206(b)(5) of this title;

(2) the pressure differential between pre-injection and predicted post-injection pressures in the injection zone;

(3) the predicted position of the CO_2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;

(4) a description of the proposed post-injection monitoring location, methods, and frequency;

(5) a proposed schedule for submitting post-injection storage facility care monitoring results to the director;

(6) the estimated cost of proposed post-injection storage facility care and closure; and

(7) consideration and documentation of:

(A) the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;

(B) the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;

(C) the predicted rate of CO_2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO_2 plume and associated pressure front;

(D) a description of the site-specific processes that will result in CO_2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;

(E) the predicted rate of CO_2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;

(F) the results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in subparagraphs (D) and (E) of this paragraph;

(G) a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO_2, formation fluids) movement;

(H) the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO_2 plume and area of elevated pressure;

(I) a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;

(J) the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and

(K) any additional site-specific factors required by the director; and

(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:

(A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;

(B) estimation techniques must be appropriate and EPA-certified test protocols must be used where available;

(C) predictive models must be appropriate and tailored to the site conditions, composition of the CO_2 stream, and injection and site conditions over the life of the geologic storage project;

(D) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;

(E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;

(F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care [~~PISC~~] timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;

(G) an approved quality assurance and quality control plan must address all aspects of the demonstration; and

(H) any additional criteria required by the director.

(n) Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).

(1) The applicant must demonstrate financial responsibility [~~and resources~~] for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided to the operator a written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.

(2) In determining whether the applicant is financially responsible, the director must rely on the following:

(A) the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)). The date of the audit may not be more than one year before the date of submission of the application to the division; and

(B) the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or

(C) if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the division.

(o) Letter from the Groundwater Advisory Unit of the Oil and Gas Division. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with Texas Water Code, §27.046.

(p) Other information. The applicant must submit any other information requested by the director as necessary to discharge the Commission's duties under Texas Water Code, Chapter 27, Subchapter B-1, or deemed necessary by the director to clarify, explain, and support the required attachments.

§5.204 Notice of Permit Actions and Public Comment Period.

(a) Notice requirements.

(1) The Commission shall give notice of the following actions:

(A) a draft permit has been prepared under §5.202(e) of this title (relating to Permit Required, and Draft Permit and Fact Sheet); and

(B) a hearing [~~that~~] has been scheduled under subsection (b)(2) of this section.

(2) General notice by publication. The Commission shall publish notice of a draft permit once a week for three consecutive weeks in a newspaper of general circulation in each county where the storage facility is located or is to be located. The Commission shall also post notice of a draft permit on the Commission's website.

(3) Methods of notification. The Commission shall give notice by the following methods:

(A) Individual notice. Notice of a draft permit or a public hearing shall be given by mailing a copy of the notice to the following persons:

(i) the applicant;

(ii) the United States Environmental Protection Agency;

(iii) the Texas Commission on Environmental Quality, the Texas Water Development Board, the Texas Department of State Health Services, the Texas Parks and Wildlife Department, the Texas General Land Office, the Texas Historical Commission, the United States Fish and Wildlife Service, other Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources, and coastal zone management plans, the Advisory Council on Historic Preservation, including any affected States (Indian Tribes) and any agency that the Commission knows has issued or is required to issue a permit for the same facility under any federal or state environmental program;

(iv) each adjoining mineral interest owner, other than the applicant, of the outermost boundary of the proposed geologic storage facility;

(v) each leaseholder and interest owner of minerals lying above or below the proposed geologic storage facility;

(vi) each adjoining leaseholder of minerals offsetting the outermost boundary of the proposed geologic storage facility;

(vii) each owner or leaseholder of any portion of the surface overlying the proposed geologic storage facility and the adjoining area of the outermost boundary of the proposed geologic storage facility;

(viii) the clerk of the county or counties where the proposed geologic storage facility is located or is proposed to be located;

(ix) the city clerk or other appropriate city official where the proposed geologic storage facility is located within city limits;

(x) any other unit of local government having jurisdiction over the area where the geologic storage facility is or is proposed to be located, and each state agency having any authority under state law with respect to the construction or operation of the geologic storage facility;

(xi) any State, Tribe, or Territory any portion of which is within the AOR of the Class VI project;

(xii) [~~(xi)~~] persons on the mailing list developed by the Commission, including those who request in writing to be on the list and by soliciting participants in public hearings in that area for their interest in being included on area mailing lists; and

(xiii) [~~(xii)~~] any other class of persons that the director determines should receive notice of the application.

(B) Any person otherwise entitled to receive notice under this paragraph may waive his or her rights to receive notice of a draft permit under this subsection.

(4) Content of notice. Individual notice must consist of:

(A) the applicant's intention to construct and operate an anthropogenic CO_2 geologic storage facility;

(B) a description of the geologic storage facility location;

(C) a copy of any draft permit and fact sheet;

(D) each physical location and the internet address at which a copy of the application may be inspected;

(E) a statement that:

(i) affected persons may protest the application;

(ii) protests must be filed in writing and must be mailed or delivered to Technical Permitting, Oil and Gas Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711; and

(iii) protests must be received by the director within 30 days of the date of receipt of the application by the division, receipt of individual notice, or last publication of notice, whichever is later; and

(F) information satisfying the requirements of 40 CFR §124.10(d)(1).

(5) Individual notice by publication. The applicant must make diligent efforts to ascertain the name and address of each person identified under paragraph (3)(A) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons requires an examination of county records where the facility is located and an investigation of any other information that is publicly and/or reasonably available to the applicant. If, after diligent efforts, an applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (3)(A) of this subsection, the applicant satisfies the notice requirements for those persons by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the director specifying the efforts that the applicant took to identify each person whose name and/or address could not be ascertained.

(6) Notice to certain communities. The applicant shall identify whether any portions of the AOR encompass an Environmental Justice (EJ) or Limited English-Speaking Household community using the most recent U.S. Census Bureau American Community Survey data. If the AOR incudes an EJ or Limited English-Speaking Household community, the applicant shall conduct enhanced public outreach activities to these communities. Efforts to include EJ and Limited English-Speaking Household communities in public involvement activities in such cases shall include:

(A) published meeting notice in English and the identified language (e.g., Spanish);

(B) comment forms posted on the applicant's webpage and available at public meeting in English and the alternate language;

(C) interpretation services accommodated upon request;

(D) English translation of any comments made during any comment period in the alternate language; and

(E) to the extent possible, public meeting venues near public transportation.

(7) Comment period for a draft permit. Public notice of a draft permit, including a notice of intent to deny a permit application, shall allow at least 30 days for public comment.

(b) Public comment and hearing requirements.

(1) Public comment.

(A) During the public comment period, any interested person may submit written comments on the draft permit and may request a hearing if one has not already been scheduled.

(B) Reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing may be required.

(C) The public comment period shall automatically be extended to the close of any public hearing under this section. The hearing examiner may also extend the comment period by so stating at the hearing.

(2) Public hearing.

(A) If the Commission receives a protest regarding an application for a new permit or for an amendment of an existing permit for a geologic storage facility from a person notified pursuant to subsection (a) of this section or from any other affected person within 30 days of the date of receipt of the application by the division, receipt of individual notice, or last publication of notice, whichever is later, then the director will notify the applicant that the director cannot administratively approve the application. Upon the written request of the applicant, the director will schedule a hearing on the application.

(B) The director shall hold a public hearing whenever the director finds, on the basis of requests, a significant degree of public interest in a draft permit.

(C) The director may also hold a public hearing at the director's discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision.

(D) Public notice of a public hearing shall be given at least 30 days before the hearing. Public notice of a hearing may be given at the same time as public notice of the draft permit and the two notices may be combined.

(E) Upon the written request of the applicant, the Commission must give notice of a hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After the hearing, the examiner will recommend a final action by the Commission. Notices shall include information satisfying the requirements of 40 CFR §124.10(d)(2) and the Texas Government Code, §2001.052.

(3) If the Commission receives no protest regarding an application for a new permit or for the amendment of an existing permit for a geologic storage facility from a person notified pursuant to subsection (a) of this section or from any other affected person, the director may administratively approve the application.

(4) If the director administratively denies an application for a new permit or for the amendment of an existing permit for a geologic storage facility, upon the written request of the applicant, the director will schedule a hearing. After hearing, the examiner will recommend a final action by the Commission.

(5) Upon making a final permit decision, the director shall issue a response to comments. The response shall specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change, and shall briefly describe and respond to all significant comments on the draft permit raised during the public comment period or during any hearing. The Commission shall post the response to comments on the Commission's internet website.

§5.205 Fees, Financial Responsibility, and Financial Assurance.

(a) Fees. In addition to the fee for each injection well required by §3.78 of this title (relating to Fees and Financial Security Requirements), the following non-refundable fees must be remitted to the Commission with the application:

(1) Base application fee.

(A) The applicant must pay to the Commission an application fee of $50,000 for each permit application for a geologic storage facility.

(B) The applicant must pay to the Commission an application fee of $25,000 for each application to amend a permit for a geologic storage facility.

(2) Injection fee. The operator must pay to the Commission an annual fee of $0.025 per metric ton of CO_2 injected into the geologic storage facility.

(3) Post-injection care fee. The operator must pay to the Commission an annual fee of $50,000 each year the operator does not inject into the geologic storage facility until the director has authorized storage facility closure.

(b) Financial responsibility.

(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The operator must

demonstrate and maintain financial responsibility [~~and resources~~] for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.

(2) In determining whether the person is financially responsible, the director must rely on:

(A) the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); and

(B) the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or

(C) if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the director.

(3) The applicant's demonstration of financial responsibility must account for the entire AOR, regardless of whether corrective action in the AOR is phased.

(c) Financial assurance. <u>The director shall consider and approve the applicant's demonstration of financial responsibility for all the phases of the geologic sequestration project, including the post-injection storage facility care and closure phase and the plugging phase, prior to issuance of a geologic storage injection well permit</u>.

(1) Injection and monitoring wells. The operator must comply with the requirements of §3.78 of this title for all monitoring wells that penetrate the base of usable quality water and this subsection for all injection wells.

(2) Geologic storage facility.

(A) The applicant must include in an application for a geologic storage facility permit:

(i) a written estimate of the highest likely dollar amount necessary to perform post-injection monitoring and closure of the facility<u>, including plugging of all wells,</u> that shows all assumptions and calculations used to develop the estimate;

(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; and

(iii) information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.

(B) A geologic storage facility shall not receive CO_2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.

(C) The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:

(i) The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of wells, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit. The cost estimate must be performed for each phase separately and must be based on the costs to the Commission of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator;

(ii) A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and

(iii) The Commission may use the proceeds of financial assurance filed under this subsection to pay the costs of plugging any well or wells at the facility if the financial assurance for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.

(D) Bonds and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form.

(i) The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

(ii) Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.

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

(I) Cancellation. An operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.

(II) Renewal. If a financial instrument expires, the operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

(III) Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration:

(-a-) the director deems the facility abandoned;

(-b-) the permit is terminated or revoked or a new permit is denied;

(-c-) closure is ordered by the director or a United States district court or other court of competent jurisdiction;

(-d-) the operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or

(-e-) the amount due is paid.

(E) During the active life of the geologic storage project, the operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instruments used to comply with paragraph (2)(C)(i) of this subsection and provide this adjustment to the director. The operator must also provide to the director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and remedial response plan.

(F) [~~(E)~~] The operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The operator must provide to the director, within 60 days of notification by the director, [~~upon request~~] an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent [~~has reason to believe that the original~~] demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.

(G) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.

(H) The requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit.

(i) The operator must maintain financial responsibility until:

(I) the director receives and approves the completed post-injection storage facility care and closure plan; and

(II) the director approves storage facility closure.

(ii) The operator may be released from a financial instrument in the following circumstances:

(I) The operator has completed the phase of the geologic storage project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the geologic storage project, if required; or

(II) The operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the operator from the previous financial instrument.

(3) The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.

(4) The director may approve a reduction in the amount of financial assurance required for post-injection monitoring and/or corrective action based on project-specific monitoring results.

(5) The operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration.

(d) Notice of adverse financial conditions.

(1) The operator must notify the Commission of adverse financial conditions that may affect the operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The operator must give such notice by certified mail.

(2) The operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.

(3) Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the operator to be

without bond coverage. The Commission must issue a notice to any operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.

§5.206 Permit Standards.

(a) General permit conditions.

(1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.

(2) The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(b) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:

(1) the injection and geologic storage of anthropogenic CO_2 will not endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources Code, §85.046(11);

(2) with proper safeguards, both USDWs and surface water can be adequately protected from CO_2 migration or displaced formation fluids;

(3) the injection of anthropogenic CO_2 will not endanger or injure human health and safety;

(4) the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons;

(5) [~~(4)~~] the reservoir into which the anthropogenic CO_2 is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic CO_2 from the storage reservoir;

(6) [~~(5)~~] the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:

(A) an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream; and

(B) a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;

(7) [~~(6)~~] the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;

(8) [~~(7)~~] the applicant has provided a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with §5.203(o) of this title (relating to Application Requirements);

(9) [~~(8)~~] the applicant has provided a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO_2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ;

(10) [~~(9)~~] the applicant has provided a signed statement that the applicant has a good faith claim to the necessary and sufficient property rights for construction and operation of the geologic storage facility for at least the first five years after initiation of injection in accordance with §5.203(d)(1)(A) of this title;

(11) [~~(10~~] the applicant has paid the fees required in §5.205(a) of this title (relating to Fees, Financial Responsibility, and Financial Assurance);

(12) [~~(11)~~] the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and

(13) [~~(12)~~] the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.

(c) Permit conditions for injection [~~Injection~~] well construction.

(1) Construction of anthropogenic CO_2 injection wells must meet the criteria in §5.203(e) of this title.

(2) Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log [~~the appropriate form~~] showing the current completion.

(3) Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical.

(d) Permit conditions for operating [~~Operating~~] a geologic storage facility.

(1) Operating plan.

(A) The operator must maintain and comply with the approved operating plan.

(B) Prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, the following information:

(i) the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by clauses (ii), (iii), (iv), (v), (vi), (vii), (viii) and (x) of this subparagraph;

(ii) any relevant updates, based on data obtained during logging and testing of the well and the formation as required by §5.203(f) of this title, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of clauses (iii), (iv), (v), (vi), (vii), and (x) of this subparagraph;

(iii) information on the compatibility of the CO_2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well;

(iv) the results of the formation testing program required by §5.203(f) of this title;

(v) final injection well construction procedures that meet the requirements of §5.203(e) of this title;

(vi) the status of corrective action on wells in the AOR;

(vii) all available logging and testing program data on the well required by §5.203(f) of this title;

(viii) a demonstration of mechanical integrity pursuant to §5.203(h) of this title;

(ix) any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m) of this subchapter, which are necessary to address new information collected during logging and testing of the well and the formation as required by this section, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m) of this title, which are necessary to address new information collected during the logging and testing of the well and the formation as required by this section; and

(x) any other information requested by the director.

(2) Operating criteria.

(A) Injection between the outermost casing protecting USDWs and the well bore is prohibited.

(B) The total volume of CO_2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO_2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.

(C) The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.

(D) The operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs.

(E) The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO_2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.

(F) The operator must comply with the following requirements for alarms and automatic shut-off systems.

(i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.

(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:

(I) immediately cease injection;

(II) take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream into any unauthorized zone;

(III) notify the director as soon as practicable, but within 24 hours;

(IV) restore and demonstrate mechanical integrity to the satisfaction of the director prior to resuming injection; and

(V) notify the director when injection can be expected to resume.

(e) Permit conditions for monitoring [~~Monitoring~~], sampling, and testing requirements.

(1) The operator of an anthropogenic CO_2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.

(2) All permits shall include the following requirements:

(A) the proper use, maintenance, and installation of monitoring equipment or methods;

(B) monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;

(C) reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).

(3) The director may require additional monitoring as necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs.

(4) The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.

(5) The operator shall comply with the following monitoring and record retention requirements.

(A) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

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

(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.

(C) Records of monitoring information shall include:

(i) the date, exact place, and time of sampling or measurements;

(ii) the individuals who performed the sampling or measurements;

(iii) the dates analyses were performed;

(iv) the individuals who performed the analyses;

(v) the analytical techniques or methods used; and

(vi) the results of such analyses.

(D) Operators of Class VI wells shall retain records as specified in this subchapter.

(f) Permit conditions for mechanical [~~Mechanical~~] integrity.

(1) The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.

(2) The operator must establish mechanical integrity prior to commencing injection. Thereafter, other [~~Other~~] than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.

(3) If the director determines that the injection well lacks mechanical integrity, the director shall give written notice of the director's determination to the operator. Unless the director requires immediate cessation, the operator shall cease injection into the well within 48 hours of receipt of the director's determination. The director may allow plugging of the well or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The operator may resume injection upon written notification of the director's determination that the operator has demonstrated the well has mechanical integrity.

(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.

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

(5) [~~(4)~~] The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.

(g) Permit conditions for AOR and corrective action. At [~~Notwithstanding the requirement in §5.203(d)(2)(B)(i) of this title to perform a re-evaluation of the AOR, at~~] the frequency specified in the approved AOR and corrective action plan or permit, and [~~the operator of a geologic storage facility also must conduct the following~~] whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:

(1) perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR and identify all wells that require corrective action;

(2) identify all wells in the re-evaluated AOR that require corrective action;

(3) perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title; [~~and~~]

(4) submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and

(5) retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.

(h) Permit conditions for emergency [~~Emergency~~], mitigation, and remedial response.

(1) Plan. The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters. The emergency and remedial response plan and the demonstration of financial responsibility must account for the AOR

delineated as specified in §5.203(d)(1)(A) - (C) of this title or the most recently evaluated AOR delineated under subsection (g) of this section, regardless of whether or not corrective action in the AOR is phased.

(2) Training.

(A) The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.

(B) The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.

(C) The operator must provide training schedules, training dates, and course outlines to Commission personnel annually and upon request for the purpose of Commission review to determine compliance with this paragraph.

(3) Action.

(A) If an operator obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:

(i) [~~(A)~~] immediately cease injection;

(ii) [~~(B)~~] take all steps reasonably necessary to identify and characterize any release;

(iii) [~~(C)~~] notify the director as soon as practicable but within at least 24 hours; and

(iv) [~~(D)~~] implement the approved emergency and remedial response plan.

(B) If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting, including plugging of the injection well, as are necessary to prevent such movement.

(4) Resumption of injection. The director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.

(i) Permit conditions for Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.

(j) Permit conditions for well [~~Well~~] plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.

(k) Permit conditions for post-injection [~~Post-injection~~] storage facility care and closure.

(1) Post-injection storage facility care and closure plan.

(A) The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.

(B) The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post-injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title [~~(relating to Permit Required)~~], as appropriate.

(C) Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.

(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO_2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.

(3) Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the director, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance that no additional monitoring is needed to assure that the geologic storage facility will not endanger USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following:

(A) the estimated magnitude and extent of the facility footprint (the CO_2 plume and the area of elevated pressure);

(B) that there is no leakage of either CO_2 or displaced formation fluids that will endanger USDWs;

(C) that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs;

(D) that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and

(E) any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.

(4) Notice of intent for storage facility closure. The operator must notify the director in writing at least 120 days before storage facility closure. At the time of such notice, if the operator has made any changes to the original plan, the operator also must provide the revised plan. The director may approve a shorter notice period.

(5) Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the director has authorized storage facility closure, the operator must plug all wells in accordance with the approved plan required by §5.203(k) of this title and submit a plugging record (Form W-3) as required by §3.14 of this title (relating to Plugging).

(6) Storage facility closure report. Once the director has authorized storage facility closure, the operator must submit a storage facility closure report within 90 days that must thereafter be retained by the Commission in Austin. The report must include the following information:

(A) documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat that has been submitted to the Regional Administrator of Region 6 of the United States Environmental Protection Agency. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks including the Latitude/Longitude or X/Y coordinates of the surface location in the NAD 27, NAD 83, or WGS 84 coordinate system, a labeled scale bar, and northerly direction arrow;

(B) documentation of appropriate notification and information to such state and local authorities as have authority over drilling activities to enable such state and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; and

(C) records reflecting the nature, composition, volume and mass of the CO_2 stream. If mass is determined using volume, the operator must provide calculations.

(7) Certificate of closure. Upon completion of the requirements in paragraphs (3) - (6) of this subsection, the director will issue a certificate of closure. At that time, the operator is released from the requirement in §5.205(c) of this title to maintain financial assurance.

(l) Permit conditions for deed [~~Deed~~] notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:

(1) a complete legal description of the affected property;

(2) that land has been used to geologically store CO_2;

(3) that the survey plat has been filed with the Commission;

(4) the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and

(5) the volume and mass of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred. If mass is determined using volume, the operator must provide calculations.

(m) Permit conditions for retention [~~Retention~~] of records.

(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

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

(2) Records of monitoring information shall include:

(A) the date, exact place, and time of sampling or measurements;

(B) the individuals who performed the sampling or measurements;

(C) the dates analyses were performed;

(D) the individuals who performed the analyses;

(E) the analytical techniques or methods used; and

(F) the results of such analyses.

(3) The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit [~~deliver~~] 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.

(n) Permit conditions for signs [~~Signs~~]. The operator must identify each location at which geologic storage activities take place, including each injection well, by a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached 24 hours a day, seven days a week in the event of an emergency.

(o) Other permit terms and conditions.

(1) Protection of USDWs. In any permit for a geologic storage facility, the director must impose terms and conditions reasonably necessary to protect USDWs. Permits issued under this subchapter shall be issued for the operating life of the facility and the post-injection storage facility care period. The director shall review each permit at least once every five years to determine whether it should be modified, revoked and reissued, or terminated. Permits issued under this subchapter continue in effect until revoked, modified, or terminated by the Commission. The operator must comply with each requirement set forth in this subchapter as a condition of the permit unless modified by the terms of the permit.

(2) Other conditions. The following conditions shall also be included in any permit issued under this subchapter.

(A) Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. However, the permittee need not comply with the provisions of the permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR §144.34.

(B) Need to halt or reduce activity not a defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(C) Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

(D) Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(E) Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.

(F) Activities not authorized. The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.

(G) Coordination with exploration. The permittee of a geologic storage well shall coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources and take all reasonable steps necessary to minimize any adverse impact on the operator's ability to drill for and produce oil and gas or geothermal resources from above or below the geologic storage facility.

(H) Duty to provide information. The operator shall furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.

(I) Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:

(i) enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;

(ii) have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;

(iii) inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and

(iv) sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.

(J) Schedule of compliance: The permit shall [~~may~~], when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title. If the time necessary for completion of any interim requirement is more than one year and is not readily divisible into stages for completion, the permit shall specify interim dates for the submission of reports of progress toward completion of the interim requirements and indicate a projected completion date.

(i) Any schedule of compliance shall require compliance as soon as possible, and in no case later than three years after the effective date of the permit.

(ii) If the schedule of compliance is for a duration of more than one year from the date of permit issuance, then interim requirements and completion dates (not to exceed one year) must be incorporated into the compliance schedule and permit.

(iii) Progress reports must be submitted no later than 30 days following each interim date and the final date of compliance.

(K) Modification, revocation and reissuance, or termination. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(L) Signatory requirement. All applications, reports, or information shall be signed and certified.

(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.

(ii) Anticipated noncompliance. The permittee shall give advance notice to the director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(iii) Transfers. This permit is not transferable to any person except after notice to and approval by the director. The director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(iv) Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.

(v) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.

(vi) Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:

(I) any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and

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

(N) Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the director, it shall promptly submit such facts or information.

(O) Other noncompliance. The permittee shall report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of this paragraph, and §5.207(a)(2)(A) of this title at the time monitoring reports are submitted. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The reports required by this subparagraph shall contain the following information:

(i) any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and

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

(P) Incorporation of requirements in permits. New permits, and to the extent allowed under §5.202 of this title modified or revoked and reissued permits, shall incorporate each of the applicable requirements referenced in this section. An applicable requirement is a State statutory or regulatory requirement that takes effect prior to final administrative disposition of the permit. An applicable requirement is also any requirement that takes effect prior to the modification or revocation and reissuance of a permit, to the extent allowed in §5.202 of this title.

(Q) Compliance with SWDA and related regulations. In addition to conditions required in all permits, the director shall establish conditions in permits as required on a case-by-case basis to provide for and assure compliance with all applicable requirements of the SWDA and 40 CFR Parts 144, 145, 146 and 124.

§5.207 Reporting and Record-Keeping

(a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information:

(1) Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.

(2) Operating reports. The operator also must include summary cumulative tables of the information required by the reports listed in this paragraph.

(A) Report within 24 hours. The operator must report the items listed in clauses (i) through (v) of this subparagraph to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The operator shall report the following items:

(i) the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir; [~~.Such report must be made orally as soon as practicable, but within 24 hours, following the discovery of the leak, and must be confirmed in writing within five working days~~]

(ii) any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW;

(iii) any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iv) any triggering of a shut-off system (i.e., down-hole or at the surface); and

(v) any failure to maintain mechanical integrity.

(B) Report within 30 days. The operator must report:

(i) the results of periodic tests for mechanical integrity;

(ii) the results of any other test of the injection well conducted by the operator if required by the director; and

(iii) a description of any well workover.

(C) Semi-annual report. The operator must report:

(i) a summary of well head pressure monitoring;

(ii) changes to the source as well as the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;

(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;

(iv) monthly annulus fluid volume added;

(v) a description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;

(vi) a description of any event that triggers a shutdown device and the response taken; and

(vii) the results of monitoring prescribed under §5.206(e) of this title (relating to Permit Standards).

(D) Annual reports. The operator must submit an annual report detailing:

(i) corrective action performed;

(ii) new wells installed and the type, location, number, and information required in §5.203(e) of this title (relating to Application Requirements);

(iii) re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission;

(iv) the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;

(v) tons of CO_2 injected; and

(vi) other information as required by the permit.

(E) Annual updates.[~~(vi)~~] The operator must maintain and update required plans in accordance with the provisions of this subchapter.

(i) [~~(I)~~] Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:

(I) [~~(-a-)~~] reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and

(II) [~~(b)~~] determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator.

(ii) [~~(II)~~] Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.

[~~(vii) other information as required by the permit.~~]

(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.

(b) Report format.

(1) The operator must report the results of injection pressure and injection rate monitoring of each injection well on Form H-10, Annual Disposal/Injection Well Monitoring Report, and the results of internal mechanical integrity testing on Form H-5, Disposal/Injection Well Pressure Test Report. Operators must submit other reports in a format acceptable to the Commission. At the discretion of the director, other formats may be accepted.

(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the Environmental Protection Agency in an electronic format approved by the director.

(c) Signatories to reports.

(1) Reports. All reports required by permits and other information requested by the director, shall be signed by a person described in §5.203(a)(1)(B) of this title, or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;

(B) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility; and

(C) the written authorization is submitted to the director.

(2) Changes to authorization. If an authorization under paragraph (1) of this subsection is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (1) of this subsection must be

submitted to the director prior to or together with any reports, information, or applications to be signed by an authorized representative.

(d) Certification. All reports required by permits and other information requested by the director under this subchapter, shall be certified as follows: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(e) 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.

(6) The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after storage facility closure.

(7) The director may require the operator to submit the records to the director at the conclusion of the retention period.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's authority to adopt.

Issued in Austin, Texas on June 13, 2023.

Filed with the Office of the Secretary of State on June 13, 2023.

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