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RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

MEMORANDUM

TO: Chairman Wayne Christian
Commissioner Christi Craddick
Commissioner Jim Wright

FROM: Haley Cochran, Attorney
Office of General Counsel

THROUGH: Alexander C. Schoch, General Counsel

DATE: August 30, 2022

SUBJECT: Amendments to 16 TAC Chapter 5, relating to Carbon Dioxide (CO2)

Attached is Staff's recommendation to adopt amendments to 16 Texas Administrative Code Chapter 5, relating to Carbon Dioxide (CO2). The amendments implement changes made during the 87th Texas Legislative Session (House Bill 1284, Regular Session, 2021) and reflect additional federal requirements to allow the Railroad Commission (the "Commission") to submit an application for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

On May 3, 2022, the Commission approved the publication of the proposed amendments in the Texas Register for a public comment period, which ended on July 1, 2022. Staff recommends that the Commission adopt the amendments with changes to the proposed text as published in the May 20, 2022, issue of the Texas Register (47 TexReg 2944). The recommended changes are described in the attached adoption preamble.

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

The Railroad Commission of Texas (the "Commission") adopts amendments to §5.101 and §5.102, relating to Purpose, and Definitions, in Subchapter A; amendments to §§5.201 - 5.207, relating to Applicability and Compliance; Permit Required; Application Requirements; Notice and Hearing; Fees, Financial Responsibility, and Financial Assurance; Permit Standards; and Reporting and Record-Keeping. Section 5.101 is adopted without changes and the remaining sections are adopted with changes to the proposed text as published in the May 20, 2022, issue of the Texas Register (47 TexReg 2944).

The Commission adopts the amendments to implement changes made during the 87th Texas Legislative Session (Regular Session, 2021) and to reflect additional federal requirements to allow the Commission to submit an application for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

The U.S. Environmental Protection Agency (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 Underground Injection Control (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 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 established a framework for projects involving the capture, injection, sequestration or geologic storage of anthropogenic carbon dioxide in Senate Bill 1387, 81st Texas Legislature, R.S., 2009. The statutes required the state to pursue primacy for the Class VI UIC program. In recent years, interest in carbon capture and storage has increased. In June 2021, Texas took an important step towards primacy by enacting House Bill 1284 (HB 1284, 87th Legislature, R.S., 2021), which gives the Railroad Commission of Texas sole jurisdiction over carbon sequestration wells (jurisdiction had previously been shared with the Texas Commission on Environmental Quality (TCEQ)).

When Texas seeks primacy over Class VI wells, its primacy application should be greatly simplified by giving a single state agency jurisdiction over Class VI permitting.

HB 1284 also amended Texas Water Code, §27.041(a) and (c), to provide the Commission with jurisdiction over a well used for geologic storage of carbon dioxide regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and is converted to the geologic storage of anthropogenic carbon dioxide.

HB 1284 also amended Texas Water Code, §27.043, to prohibit the Commission from issuing a permit for the conversion of a previously plugged and abandoned Class I injection well, including any associated waste plume, to a Class VI injection well.

HB 1284 amended Texas Water Code, Chapter 27, Subchapter C-1, by adding §27.0461, relating to letter of determination from Commission, which requires that a person making an application to the Commission for a Class VI permit must submit with the application a letter of determination from TCEQ concluding that drilling and operating an anthropogenic carbon dioxide 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.

HB 1284 amended Texas Water Code, §27.048(b), to require that the Commission seek primacy to administer and enforce the program for the geologic storage and associated injection of anthropogenic carbon dioxide in this state, including onshore and offshore geologic storage and associated injection.

The Commission's Class II program was approved under §1425 of the SDWA, which requires that the state's program be effective in preventing endangerment of USDWs. However, EPA must review the Commission's Class VI program for geologic sequestration of carbon dioxide under §1422 of the SDWA, which requires that a state's program meet the minimum federal requirements. The amendments ensure that the Commission's regulations meet the minimum federal requirements for Class VI UIC wells.

The Commission received 17 comments on the proposal, five from associations (the Greater Houston Partnership, NARO-Texas, the Permian Basin Petroleum Association (PBPA), The Texas Industry Project (TIP), and the Texas Oil and Gas Association (TXOGA)), ten from companies or organizations, and two from individuals. The Commission also received one comment submitted on behalf of 37 Texas-based organizations and individuals. The Commission appreciates these comments.

General Comments

The Port of Corpus Christi Authority, the Greater Houston Partnership, the Carbon Neutral Coalition, Calpine Corporation, the Energy Advance Center (EAC), PBPA, TXOGA, TIP, and Denbury Carbon Solutions, LLC (Denbury) expressed support for the Commission’s Class VI primacy application to the EPA. The Environmental Defense Fund (EDF) commented that, in most respects the Commission’s proposed rules are technically excellent and EDF is generally supportive of the Commission's approach. The Commission appreciates the support of these commenters.

Commission Shift and the Texas-based organizations and individuals commented that they do not support the Commission's pre-application for Class VI primacy. These commenters believe the Commission's oversight and response to emergencies and active contamination caused by modern and legacy wells is weak. In addition to changes recommended in Chapter 5, the Texas-based organizations and individuals recommended the Commission consider a thorough overhaul of its monitoring and enforcement programs for both the oil and gas division and the pipeline safety department. The Texas-based organizations and individuals oppose the current annual Oil and Gas Division Monitoring and Enforcement Strategic Plan required by House Bill 1818 because it has proven to be slow and insufficient in addressing the many serious structural problems with monitoring and enforcement at the Commission.

The Commission disagrees. The Commission is continually working to improve its ability to analyze and measure the effectiveness of its oil and gas monitoring and enforcement program. House Bill 1818 (85th Legislature, Regular Session, 2017) directed the Commission to develop an annual plan to assess the most effective use of its limited resources to protect public safety and minimize damage to the environment. The purpose of this plan is to define and communicate the Oil and Gas Division's strategic priorities for its monitoring and enforcement efforts. The plan confirms many of the division's current priorities as well as establishes direction for data collection, stakeholder input, and new priorities for future fiscal years. The draft program description and memorandum of agreement with EPA mirror the Commission's existing approach to compliance and enforcement for the UIC program. Enforcement and compliance records for UIC wells can be accessed through the Commission's online database. A listing of the information concerning compliance and enforcement with the Commission's Oil & Gas Division is available on the Commission's website at the following link: https://www.rrc.texas.gov/oil-and-gas/compliance-enforcement/.

Regarding the request to overhaul the Commission's enforcement program for pipeline safety, that comment is outside the scope of the rulemaking to amend Chapter 5. Further, the statutory changes made by House Bill 1818 regarding the Oil and Gas Division Monitoring and Enforcement Strategic Plan do not address pipeline safety issues.

The Texas-based organizations expressed opposition to any infrastructure approved by commissioners who have financial interests related to operators who appear on the Personal Financial Statements that the commissioners submit to the Texas Ethics Commission. The Texas-based organizations and individuals requested that the Commissioners affirm that they will not make decisions about companies related to campaign donors from which the Commissioners have accepted more than $1,000. This comment is also outside the scope of this rulemaking.

Commission Shift and the Texas-based organizations commented that communities in the Gulf Coast and the Permian Basin who are likely to see the brunt of this development have expressed that they are already overburdened with the risks and health impacts of unchecked petrochemical development. The Texas-based organizations commented that many communities in the Texas Gulf Coast, the Eagle Ford Shale, and the Permian Basin regions are predominantly people of color, low income, and/or are already overburdened by heavy industrial activity and poor state oversight and that these communities will continue to be disproportionately affected by carbon capture and storage. The Texas-based organizations believe state agencies ignore the public's concerns and requests for information, and also believe private industry has unequal leverage over state agencies compared to the public. Nonetheless, the Texas-based organizations and individuals ask that the Commission participate in dialogue with the public in an effort to resolve potential conflicts posed by Class VI injection.

The Commission agrees that there are areas of Texas with a concentration of industrial activity that are also in the area of disadvantaged communities. The program requirements and rule amendments are designed to ensure that where geologic storage is deployed, projects are permitted, sited, constructed, operated, and closed in a manner that protects USDWs from endangerment. The regulations build on the long-standing framework of the UIC program, under which the injection of billions of gallons of liquids has been regulated for decades. The amendments enhance this existing framework with requirements that are tailored to the unique nature of large-scale geologic storage of carbon dioxide. These additional protective requirements include more extensive geologic testing, detailed computational modeling of the area of review (AOR) and periodic reevaluations, detailed requirements for monitoring and tracking the carbon dioxide plume and pressure front, and extended post-injection monitoring and site care. The intent of the emergency and remedial response requirements is that if the operator obtains any evidence that USDWs may be endangered, the operator must cease injection, take all steps reasonably necessary to identify and characterize any release, notify the director, and implement the approved emergency and remedial response plan.

The Port of Corpus Christi Authority commented that, when primacy is granted, the Commission should be allowed in the first five years to increase staff to review Class VI UIC applications.

The Commission will increase staffing to implement the Class VI UIC program. The duties and responsibilities for the Class VI UIC program will predominantly be handled by UIC staff. The Class VI UIC Manager will have a significant technical management role in the program, being responsible initially for conducting detailed aspects of the reservoir modeling and reservoir simulation technical review. Overall, management will also include supervising staff of geologists and engineers selected for the Class VI UIC team on the basis of their previous experience and expertise in reservoir modeling and simulation. With growth of the program in Texas, additional resources will be devoted to the program to continue to meet or exceed requirements for program performance.

The Texas-based organizations and Commission Shift commented that the sitting Commissioners' denial that climate change is human caused and their derision of federal efforts to curtail greenhouse gas emissions from the oil and gas supply chain give little confidence that the Commission will be prepared to improve its monitoring and enforcement function in a manner that prevents leaks and failures on carbon dioxide pipelines, Class VI wells, and Class II wells. The organizations requested that the Commission respond on whether it will consider passing a resolution to acknowledge the vast body of scientific evidence supporting that climate change is human caused, that significantly reducing emissions of carbon dioxide in the next decade is an essential mitigation tool to curb the worst effects of climate change, and that it is the Commission's duty to plan for and make every reasonable effort to prevent harm to communities from climate change and greenhouse gas mitigation infrastructure.

The Commission disagrees. The UIC program's authority under the SDWA focuses on ensuring that geologic storage projects are permitted, sited, constructed, operated, monitored, and closed in a manner that is protective of USDWs. Issues such carbon capture and pipeline transportation of carbon dioxide are important; however, these issues are outside of the UIC program's authority under the SDWA and beyond the scope of this rulemaking. Comments pertaining to climate and energy policy are not relevant to the substance of the Class VI primacy application or the proposed rule amendments.

Similarly, the Texas-based organizations recommended that the Commission support federal rulemakings to reduce methane emissions across the natural gas supply chain and significantly limit the reasons it allows for granting flaring and venting rule exceptions. This comment is also beyond the scope of this rulemaking.

The Texas-based organizations commented that the proposed rule changes will set the stage for the buildout of additional carbon capture and storage infrastructure, which the Intergovernmental Panel on Climate Change stated in its Working Group III report has "not been tested at a large scale," and entails many uncertainties and risks. The Texas-based organizations also commented that CO_2 capture costs present a key challenge. The capital cost of a coal or gas electricity generation facility with CCS is almost double one without CCS. Additionally, the energy penalty increases the fuel requirement for electricity generation by 13–44%, leading to further cost increases. The additional fuel requirement will mean additional carbon emissions. Therefore, installation of CCS infrastructure, which requires the use of Class VI wells, or Class II wells that may be converted to Class VI wells, will run counter to any effort to decarbonize the state of Texas.

The Commission disagrees. In its most recent Working Group III report *Climate Change 2022: Mitigation of Climate Change* report, the International Panel on Climate Change (IPCC) reaffirmed the central role that CCUS will play reducing carbon dioxide levels in the atmosphere. Carbon capture and storage technologies have been proven at commercial scale and there is an extensive network of global knowledge about carbon dioxide storage. Geologic storage of carbon dioxide for the purpose of reducing carbon dioxide emissions, began in 1996 with the Sleipner project in Norway. Today, there are 12 commercial scale facilities capturing and safely storing carbon dioxide in the United States. With respect to the cost of CCUS, the Commission agrees that the capture element of carbon capture, use, and storage (CCUS) is costly. However, in its Fifth Assessment Report, the Intergovernmental Panel on Climate Change (IPCC) concluded that the costs for achieving atmospheric carbon dioxide levels consistent with holding average global temperatures to 2°C will be more than twice as expensive without CCUS. (IPCC, 2014: Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)). IPCC, Geneva, Switzerland, 151 pp.)

The Texas-based organizations commented that the Commission has not fulfilled its duty to protect USDWs in Texas, its monitoring and enforcement program fails to adequately steward natural resources and the environment or protect personal and community safety, and it is clear that Commission leadership lacks the necessary care and understanding of the importance of preventing failures with carbon dioxide infrastructure and mitigating greenhouse gas emissions. The Texas-based organizations requested that the Commission undertake a thorough overhaul of its monitoring and enforcement programs for both the oil and gas division and the pipeline safety department. Under the current levels of oversight and enforcement from the Commission, the Texas-based organizations believe that EPA would have reason to rescind its delegation of authority to the Commission to implement and enforce the Underground Injection Control program under the Safe Drinking Water Act.

The Commission considers the comment regarding monitoring and enforcement programs for both the oil and gas division and the pipeline safety department beyond the scope of this rulemaking. With respect to the Commission’s UIC program, EPA performs annual evaluations of the Commission’s UIC program performance. These annual evaluations have been positive. EPA Region 6’s 2021 annual evaluation acknowledged that the Commission’s UIC program compliance surveillance and enforcement program for Class II and III injection wells regulated by the Commission appears to be effective. A large percentage of the authorized injection wells in Texas were inspected in FY 2020 and the Commission also collected and reviewed operator-submitted monitoring information from a large percentage of the Class II well inventory. Those numbers assure more than adequate inspection and monitoring surveillance actions. The 2021 annual evaluation specifically noted innovative measures taken by the Commission to address program challenges, such as induced seismicity and continued improvements of data reporting and recordkeeping.

The Texas-based organizations expressed concern with the Commission's ongoing practice of allowing facilities whose permits have been revoked to continue operating until a new final permit is reissued. Facilities that have acted so badly as to cause harm to their neighbors, groundwater, or air quality should not be allowed to continue operating under a revoked permit.

The UIC program is aware of no wells that have been allowed to continue to operate when the permit has been revoked. The Commission made no change in response to this comment.

TXOGA and TIP request that the Commission, in consultation with EPA, outline a process whereby any Class VI UIC well permit applications pending before EPA, at the time primacy is granted, would be transferred to the Commission for further processing. In that same spirit, we seek assurance that a permit pursued under the EPA application process would not have to start over when the Commission receives primacy.

The Commission and EPA have had ongoing discussions about transition upon granting of primacy. In addition, both EPA and the Commission are reviewing any applications received until primacy is granted in tandem to ensure that the permit processing and transition is as smooth as possible.

Rule-Specific Comments

§5.101

The Texas-based organizations commented that the stated purpose of the rules is protection of underground sources of drinking water, but the rules make no reference to public protection in the event of leakage. The organizations pointed to the carbon dioxide pipeline rupture near Satartia, Mississippi which revealed that carbon dioxide sinks when it is released and can cause asphyxiation.

The Commission makes no change in response to these comments. Although, as indicated, the purpose of the Class VI UIC regulations is the protection of USDWs, Texas Water Code §27.051 authorizes the Commission to issue a permit for the geologic storage of carbon dioxide if it finds, among other things, that the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation; that, with proper safeguards, both ground and surface fresh water can be adequately protected from carbon dioxide migration or displaced formation fluids; and that the injection of anthropogenic carbon dioxide will not endanger or injure human health and safety. Section 5.206(b)(3) of the rules states that the director may issue a permit if the applicant demonstrates, and the director finds, that injection of anthropogenic carbon dioxide will not endanger or injure human health and safety. The incident at Satartia, Mississippi, was the result of a pipeline rupture, which is beyond the scope of the geologic storage regulations. Establishment and enforcement of regulations relating to standards and monitoring of carbon dioxide pipelines are the jurisdiction of the U.S.

Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Regulation of pipelines is beyond the scope of this rulemaking.

§5.102

Texas 2036 commented that proposed §5.102(27) defines the types of underground storage facilities used for the geologic storage of CO_2. The only geologic feature described within the definition is "underground reservoir." While this term is broad, Texas 2036 recommended that it be amended to include the specific types of formations described within 26 USC §45Q(d)(2). This section of federal law describes those formations that may be used for secure geological storage for the purposes of the federal carbon dioxide sequestration tax credit. In particular, §45Q(d)(2) of the federal Internal Revenue Code lists "deep saline formations, oil and gas reservoirs, and unmineable coal seams" as geologic formations that shall qualify as secure geological storage. Texas 2036 recommended that these formations be included in the definition of "geologic storage facility" to ensure consistency between the adopted rule and the federal requirements for carbon dioxide sequestration tax credits.

The Commission agrees with this comment. EPA's Class VI regulations do not prohibit injection into any specific formation types (e.g., unmineable coal seams, basalts, and other formations). They afford all formations equal treatment and allow the regulatory flexibility to determine if injection at a particular site and depth is the appropriate approach. Title 40 CFR §144.3 defines "geologic sequestration" as "the long-term containment of a gaseous, liquid, or supercritical CO_2 stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport." In the adoption preamble to the Class VI regulations, (75, FR 77231, Dec. 10, 2010), EPA noted that some research on CO_2 injection for geologic sequestration into various formations including shallow, volcanic rocks such as flood basalts (McGrail, *et al.,* 2006) and coal seam injection (Dooley, *et al.,* 2006; IPCC, 2005; MIT 2007; White *et al.,* 2005) illustrates the potential for geologic sequestration in these formations. However, EPA noted that some types of formations, such as coal seams and basalts, are typically shallow and above the lowermost USDW, which would require an injection depth waiver (§146.95) provided the operator can demonstrate that such injection can be performed in a manner that protects USDWs. Therefore, the Commission adopts §5.102(27), (28) and (45), as renumbered upon adoption, with changes to address this comment.

Texas 2036 commented that Chapter 5 includes multiple references to "fluids" and "injection fluids" without describing what these substances include. For example, §5.202(d)(2)(B)(i)(III) authorizes the termination of a permit if "fluids are escaping or likely to escape the injection zone." Further, the delineation of the area of review and corrective action required of a permit applicant in §5.203(d) must contemplate the relationship between injected fluids and USDWs. And, the permitting standards described within §5.206 prohibit the movement of "fluids" or "injection fluids" that endanger USDW. It is unclear in these and other examples precisely what type of fluid is subject to the applicable rule. The terms "fluid" or "injection fluid" are not defined for the purposes of Chapter 5. While proposed §5.102(24) defines "formation fluid," the definitions section in §5.102 does not define the other fluids listed throughout the chapter. Defining "fluid or injection fluid" in §5.102 would clarify those specific substances – namely CO_2 – subject to the applicable regulations within the proposed rules. Towards that end, Texas 2036 recommended that the Commission amend the rule to define "fluid or injected fluid" that includes gaseous, liquid, or supercritical CO_2 to provide greater clarity to Chapter 5's requirements.

The Commission agrees that a definition for "fluid" would be helpful because with respect to the UIC program, the term "fluid" could mean formation fluids or injected fluids. The Commission has added a definition for "fluid" to §5.201.

The Texas-based organizations and an individual recommended the Commission clarify the definition of "permit" proposed in §5.102(36) and adopted in renumbered paragraph (40) by adding "this" before "chapter." The Commission agrees with this comment and has made the recommended change.

The Texas-based organizations recommended that the Commission modernize its methods of notice and include posts on social media, and not just newspapers. The organizations also recommended that the Commission consider setting up email lists that will enable the public to more easily opt into regional notices that may be relevant to them. The Texas-based organizations commented that it is not clear whether the applicants will be required to notify new individuals if the outermost boundary of the facility changes with a permit modification. Similarly, the comment notes there is incongruence in the rule with considering communities in the Area of Review versus the outermost boundary of the facility. The Texas-based organizations believe people who own land or reside in an area within a certain radius of the expected injection plume should be included in notice requirements. The organizations also recommended that notice be provided in Spanish without request, and instructions on how to obtain language accommodation should be provided in other languages. Finally, the organizations oppose placing the burden of proof on poorly-resourced individuals to prove that they "will" be impacted in order to qualify as an "interested person."

The Commission makes no change in response to this comment. Under Section 5.204, the Commission will provide both published and individual notice when a draft permit has been prepared and a hearing has been scheduled. Such notice would be mailed to each adjoining mineral interest owner in the outermost boundary of the proposed geologic storage facility; each leaseholder of minerals lying above or below the proposed storage reservoir; each adjoining leaseholder of minerals offsetting the outermost boundary of the proposed geologic storage facility; each owner or leaseholder of any portion of the surface overlying the proposed storage reservoir and the adjoining area of the outermost boundary of the proposed geologic storage facility; the clerk of the county or counties where the proposed storage facility is located; the city clerk or other appropriate city official where the proposed storage facility is located within city limits; any other unit of local government having jurisdiction over the area where the facility is or is proposed to be located; 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 any other class of persons that the director determines should receive notice of the application. Notice must also be published. The Commission will develop a form for requesting to be on the list and include a link to the form on the Commission's webpage. The Commission will consider how to best use social media applications for important information and will encourage operators to use similar technologies to keep the public informed of geologic storage projects.

TXOGA and TIP request that "interested person", as defined in §5.202(d)(1), be included as a newly defined term in §5.102. This will provide greater consistency and clarity throughout the proposed rule, as the terms "interested person" and "affected person" are used throughout the proposed rule but have distinct meanings. The Texas-based organizations commented that the definition of interested persons and affected persons may be overly narrow, excluding people who may be impacted from these facilities from participating in hearings. The threshold for participation by the public in permit processes should be inclusive of all who may be potentially impacted.

The term "interested persons" is not defined in the federal regulations (or other state regulations) because the term encompasses any person who expresses an interest in an application, permit, or Class VI UIC well. However, the Commission agrees that clarification would be beneficial and adopts §5.102 with the requested change.

PBPA expressed concern that the definition of affected person in §5.102(1) could include parties claiming economic damage that is not linked to the facility. PBPA recommended that the damage be tied to permitted activity only.

The Commission agrees with this comment and adopts §5.102(1) with a change to state that an affected person is 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. This modified definition is consistent with the definition found in 16 TAC §3.81, relating to Brine Mining Injection Wells. Brine mining wells are regulated under the UIC program as Class III injection wells. The Commission's Class III brine mining well program was approved by EPA under Section 1422 of the SDWA. Therefore, the revised definition of "affected person" should be acceptable.

NARO-Texas commented that, throughout the proposed amendments, reference is made to the "good faith claim to the necessary and sufficient property rights to operate the geologic storage facility."

However, §5.102, relating to definitions, does not define the term "good faith." In the context of obtaining an oil and gas well drilling permit, an operator must demonstrate a good faith claim to the right to drill, or more thoroughly stated, a "factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate." *See Opiela v. Railroad Commission of Texas*, Cause No. D-1-GN-20-000099, pending in the 53rd District Court of Travis County, Texas. NARO-Texas recommended that the Commission define "good faith" to ensure that applicants properly demonstrate a continuing possessory right in a geologic storage facility based upon a factually supported and recognized legal theory.

The Commission agrees that a definition would be helpful and adopts §5.102 with a definition for "good faith claim" similar to that in 16 TAC §3.15(a)(5) of this title (relating to Surface Equipment Removal Requirements and Inactive Wells).

The Texas-based organizations commented that the definition of "Mechanical integrity" relies on whether "significant leaks" or "significant fluid movement" can be detected. They requested clarification as to how the Commission defines "significant" leaks or fluid movement. Part B of the "Mechanical integrity" definition explains that the Commission will consider test deviations that cannot be explained by the standard of error for the test. The Texas-based organizations inquired whether this be the only way of defining "significant" leaks, or whether the Commission also considers a leak to be "nonsignificant" despite test deviations that are not within the test's normal standard of error.

The Commission considers a successful mechanical integrity test to be one in which the applied test pressure stabilizes within 10% of the required test pressure and remains stabilized for a minimum of 30 minutes (60 minutes if testing with a gas-filled annulus). The applied test pressure may vary up to 10% prior to stabilizing but must not gain or lose any pressure for the 30/60 minute stabilization period. An "inconclusive" mechanical integrity test is one that does not stabilize but loses less than 10% of the test pressure within the 30-minute test period (60 minutes if testing with a gas-filled annulus). The test may also be ruled inconclusive for various procedural problems. A "failed" test is one in which the applied test pressure loses 10% or more within the 30-minute test period (60 minutes if testing with a gas-filled annulus). An inconclusive mechanical integrity test is one that fails to demonstrate the absence of tubing, packer or casing leaks but does not clearly indicate leaks. There will be minor variations in many data sets over time. Significance can be determined by a statistical analysis of the data. The Commission made no change in response to this comment.

The Texas-based organizations suggested that the Commission modify the definition of "plugging," which is defined as 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, to include supercritical carbon dioxide.

The Commission declines to make the requested change. The definition is consistent with the definition in 40 CFR §144.3.

The Texas-based organizations recommended that the Commission revise the definition of "operator" from "A person, acting for itself . . ." to "A person, acting for themselves . . ."

The Commission declines to make the requested change.

WSP USA (WSP) recommended adoption of EPA's full definition for the zone of confinement from 40 CFR §146.81(d).

The Commission agrees with this comment and adopts §5.102(13) with the recommended change such that confining zone is defined as: "A geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) 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(s) that acts as a barrier to fluid movement."

With respect to proposed §5.102(26), relating to the definition of geologic storage, the Texas-based organizations requested clarification of the term "long-term" in this definition and recommended that the Commission consider defining "long-term" in the rule.

The Commission declines to make any changes. Section 120.001 of the Texas Natural Resources Code defines the term "sequester" as to inject carbon dioxide into a geological formation in a manner and under conditions that create a reasonable expectation that at least 99% of the carbon dioxide injected will remain sequestered from the atmosphere for at least 1,000 years." However, this definition is limited to Clean Energy Projects, which are defined as "a project to construct a coal-fueled, natural gas-fueled, or petroleum coke-fueled electric generating facility, including a facility in which the fuel is gasified before combustion, that will: (A) have a capacity of at least 200 megawatts; (B) meet the emissions profile for an advanced clean energy project under §382.003(1-a)(B), Texas Health and Safety Code; (C) capture at least 70% of the carbon dioxide resulting from or associated with the generation of electricity by the facility; (D) be capable of permanently sequestering in a geological formation the CO_2 captured; and (E) be capable of supplying the carbon dioxide captured for purposes of an EOR project." There is no statutory definition of the term "long-term" with respect to geologic storage of carbon dioxide.

§5.201

An individual commented on the amendments in §5.201(b), requesting that the Commission add a title to the subsection and include the factors that the Commission will consider when determining whether there is an increased risk to USDWs such that a Class VI permit is required. The individual commented that, while it is appropriate to incorporate these factors, it is also important to recognize that the Class VI regulations do not dictate exactly how the director should apply these factors when making the determination. More importantly, the factors themselves will play very different roles in affecting the assessment of risks.

PBPA expressed concern that the changes in §5.201(b)(2) could be construed to apply to Class II wells, for which the rule is not intended, and asked that the Commission clarify the provision to address circumstances where a Class II well has been converted to a Class VI well.

The Commission agrees and adopts §5.201(b) with a change clarifying that (b)(2) applies to a well that is permitted for the injection of CO_2 for the purpose of enhanced recovery.

TXOGA and TIP commented on the language in §5.201(c) that cross-references the factors listed in §5.201(b) for determining whether a Class II well used for the disposal of acid gas containing CO_2 should be converted to a Class VI well. Rather than cross-referencing the factors applicable to EOR wells, TXOGA and TIP recommended including the following specific factors applicable to acid gas disposal wells: the reservoir pressure within the injection zone; the quantity of acid gas being disposed of; distance between the injection zone and USDWs; suitability of the disposed waste AOR delineation; quality of abandoned well plugs within the AOR; the source and properties of injected acid gas; and any additional site-specific factors as determined by the Commission.

TXOGA and TIP further recommended that the Commission delete the words "from a single lease, unit, field, or gas processing facility" from the first sentence of proposed §5.201(c). TXOGA and TIP stated that the language in §5.201(c) appears to place new and unnecessary restrictions on the use of Class II wells for the injection of CO_2 and other acid gases generated from oil and gas activities. TXOGA and TIP are concerned that this language could be construed to require Class VI permits for any acid gas disposal well used to inject CO_2 or other acid gases that come from more than one lease, field, unit, or gas processing facility. TXOGA and TIP note that there is no requirement under federal law or in the Commission's current rules that places such a restriction on the use of Class II acid gas disposal wells. Under both the federal UIC rules and current Commission rules, CO_2 and other acid gases can be injected into a Class II well as long as they are generated from oil and gas activities, without regard to the number of sources or locations. Further, both the Treasury Department and EPA have acknowledged that Class II UIC wells may be used for the permanent sequestration of CO_2 generated from oil and gas activities if the operator has a Monitoring, Reporting, and Verification (MRV) plan that has been approved by EPA. EPA has approved MRV plans for significant carbon sequestration projects using Class II wells in New Mexico and Wyoming and there is no reason for operators in Texas to be put at a competitive disadvantage compared to operators in other states.

The Commission adopts §5.201(c) with a change to remove the reference to a single lease and to add the factors recommended by TXOGA and TIP as factors more applicable to acid gas disposal wells.

With respect to §5.201(f), relating to injection depth waiver, an individual recommended that injection depth waivers be available for existing wells through amendment of a permit to use an alternative injection interval.

The Commission agrees with this comment and adopts §5.201(f) with a change to incorporate the commenter's recommended language.

The Texas General Land Office (GLO) expressed concern that the rules allow waivers of the federal depth limitations for Class VI wells as such waivers could place USDW at risk and could result in CO_2 being stored at, or migrating to, depths shallower than required to maintain the fluid in its dense supercritical state. The GLO also expressed concerns because storage of CO_2 in the less dense vapor phase makes inefficient use of available pore space; flashing of dense supercritical CO_2 into the vapor phase is a safety concern: the lower density of the vapor phase increases buoyancy forces and, consequently, the risk of vertical migration; and there is evidence that vapor phase CO_2 can flow more easily through caprock seal pores than supercritical phase fluid, even at otherwise constant pressure differentials.

The Commission disagrees. The federal regulations at 40 CFR §146.96 allow an operator to seek a waiver of the Class VI injection depth requirements. In seeking a waiver of the requirement to inject below the lowermost USDW, the operator must submit a supplemental report concurrent with its permit application. The supplemental report must include: (1) a demonstration that the injection zone is laterally continuous, is not a USDW, and is not hydraulically connected to USDWs; does not outcrop; has adequate injectivity, volume, and sufficient porosity to safely contain the injected carbon dioxide and formation fluids; and has appropriate geochemistry; (2) a demonstration that the injection zone is bounded by laterally continuous, impermeable confining units above and below the injection zone adequate to prevent fluid movement and pressure buildup outside of the injection zone; and that the confining unit is free of transmissive faults and fractures and characterization of the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs; (3) a demonstration, using computational modeling, that USDWs above and below the injection zone will not be endangered as a result of fluid movement; (4) a demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of the injectate in lieu of requirements at §146.86(a)(1) and will meet well construction requirements in §146.95(f); (5) a description of how the monitoring and testing and any additional plans will be tailored to the project to ensure protection of USDWs above and below the injection zone(s) if a waiver is granted; (6) information on the location of all the public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and (7) any other information requested by the director to inform the Regional Administrator's decision to issue a waiver.

To inform the Regional Administrator's decision on whether to grant a waiver of the injection depth requirements at §§144.6, 146.5(f), and 146.86(a)(1), the director must submit to the Regional Administrator, an evaluation of the following information as it relates to siting, construction, and operation of a geologic sequestration project with a waiver: the integrity of the upper and lower confining units; the suitability of the injection zone(s) (e.g., lateral continuity; lack of transmissive faults and fractures; knowledge of current or planned artificial penetrations into the injection zone(s) or formations below the injection zone); the potential capacity of the geologic formation(s) to sequester carbon dioxide, accounting for the availability of alternative injection sites; all other site characterization data, the proposed emergency and remedial response plan, and a demonstration of financial responsibility; community needs, demands, and supply from drinking water resources; planned needs, potential and/or future use of USDWs and non-USDWs in the area; planned or permitted water, hydrocarbon, or mineral resource exploitation potential of the proposed injection formation(s) and other formations both above and below the injection zone to determine if there are any plans to drill through the formation to access resources in or beneath the proposed injection zones/formations; the proposed plan for securing alternative resources or treating USDW formation waters in the event of contamination related to the Class VI injection activity; and, any other applicable considerations or information requested by the director.

Application for an injection depth waiver also requires consultation with the Public Water System Supervision Directors of all States and Tribes having jurisdiction over lands within the AOR of a well for which a waiver is sought and any written waiver-related information submitted by the Public Water System Supervision Director(s) to the UIC director.

The application further requires that the director give public notice that a waiver application has been submitted. The notice must clearly state:(1) the depth of the proposed injection zone(s); (2) the location of the injection well(s); (3) the name and depth of all USDWs within the area of review; (4) a map of the AOR; (5) the names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and (6) the results of UIC-Public Water System Supervision consultation.

If the Regional Administrator determines that additional information is required to support a decision, the director shall provide the information. The Regional Administrator may require that public notice of the new information be initiated. In no case may a director of a State-approved program issue a waiver without receipt of written concurrence from the Regional Administrator. If a waiver of the requirement to inject below the lowermost USDW for geologic sequestration is granted, the operator of the Class VI well must comply with certain additional requirements to ensure protection of USDWs above and below the injection zone(s). The Commission made no change in response to this comment.

EDF and one individual recommended amending §5.201(g) to clarify that the 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. Title 40 CFR §261.3 establishes the definition of hazardous waste. Carbon dioxide streams injected for geologic storage could potentially exhibit a hazardous characteristic (e.g., corrosivity) that would meet the definition of hazardous waste. However, EPA promulgated 40 CFR §261.4(h) to provide that certain carbon dioxide streams are not a hazardous waste, provided specified conditions are met. Thus, EDF recommended adding the reference to 40 CFR part 261 to ensure that §5.201(g) incorporates the applicability of 40 CFR §261.4(h).

The Commission agrees with EDF and the individual and adopts §5.201(g) with a change consistent with the definition of carbon dioxide (CO_2) stream in §5.102(7), which states that the term does not include any CO_2 stream that meets the definition of a hazardous waste under 40 CFR Part 261.

§5.202

An individual commented that the language in §5.202(a)(1) is too broad. To avoid confusion over the ability to construct a well, such as a stratigraphic test well, that will later be converted to a Class VI well, it would be better to use "Class VI well" in subsection (a)(1). In addition, the individual expressed concern that there is potential for precluding activities are essential steps but that are not within the purview of the UIC program because the definition of "geologic storage facility" is so broad and includes surface buildings and equipment, surface and subsurface rights and appurtenances, and any reasonable and necessary areal buffer and subsurface monitoring zones. The individual noted that because section 45Q of the IRS Code requires construction to start before specified deadlines, the Commission's regulation should not include language that might preclude an operator from constructing capture equipment (e.g., compressors) that might be located within a geologic storage facility. Thus, the individual recommended replacing the reference in §5.202(a)(1) to "an anthropogenic CO_2 injection well" with a reference to "a Class VI injection well." The individual also recommended striking language relating to construction.

The Commission partly agrees and adopts §5.202(a) with a change to clarify that the provision applies to an anthropogenic CO_2 injection well for geologic storage regulated under Subchapter B. The Commission declines to delete the reference to constructing a geologic storage facility because the language in 5.202(a) reflects Texas Natural Resources Code, §27.043, which states that a person may not begin drilling or operating an anthropogenic carbon dioxide injection well for geologic storage or constructing or operating a geologic storage facility regulated under this subchapter without first obtaining the necessary permits from the Railroad Commission.

The individual also recommended §5.202(e)(1)(C) be revised by adding "other than a denial" to differentiate a denial from an actual draft permit that would include permit conditions.

The Commission agrees with this comment and adopts a change in §5.202(e)(1)(C) to clarify the intent.

The GLO commented that injection rate increases should be allowed only after an approved permit amendment. The proposed rules state that "an operator must file an application to amend an existing geologic storage facility permit with the director . . . prior to increasing the permitted injection pressure." The GLO recommended that the Commission revise this language to also require an application to amend an existing permit for injection rate increases (as measured on a mass flow basis). The rate of injection can control reservoir sweep efficiency and, consequently, the degree to which residual phase trapping can act to sequester the carbon. Poor sweep efficiency can also result in a "pancake" of carbon rising to the top of the injection zone where it will migrate further in the lateral direction it otherwise would under more uniform reservoir contact conditions. Injection strategy – including rate management – can also affect ultimate storage efficiency.

The Commission agrees and adopts §5.202(b)(1)(B) with a change to address this issue.

The Texas-based organizations commented that §5.202(b) requires an operator to file an application to amend a permit prior to adding injection wells. The organizations requested clarification as to the number of injection wells anticipated for each geologic storage facility, whether there is a maximum number of wells the Commission anticipates would be located at any given facility, and whether operators will report on a per well or a per facility basis.

The Commission is unable to speculate on number of wells at any given future facility. However, recent proposed facilities have typically had less than ten injection wells at a facility. The Commission's rules do not limit the number of injection wells at a facility. Commission staff will assess compliance for each injection well at a facility. However, the Commission expects that a facility operator may submit reports for injection wells at the same facility together and that Commission staff may review compliance of injection wells together for efficiency. The Commission made no change in response to this comment.

With respect to §5.202(c)(1), the Texas-based organizations requested that the Commission advise as to remedies available to the Commission to allow for agency review of an applicant's notice of intended permit transfer in the case where the director has financial interest in the companies involved and review of such notice would trigger U.S. Securities and Exchange Commission fiduciary and insider trading restrictions and/or rules.

The Texas Government Code, Chapter 572, prohibits, among other things, state officers and employees from having a direct or indirect interest, including financial and other interests, or engaging in a business transaction or professional activity, or incurring any obligation of any nature that is in substantial conflict with the proper discharge of the officer's or employee's duties in the public interest. The Commission's handbook incorporates the provisions of Chapter 572, including prohibiting

Commission employees and officers from making personal investments that could reasonably be expected to create a substantial conflict between the employee's private interest and the public interest. The Commission made no change in response to this comment.

TXOGA and TIP recommended that the Commission revise the language in §5.202(d)(1)(C) describing "interested person" to instead refer to "any affected person."

The Commission notes that 40 CFR §124.5 states that permits may be modified, revoked and reissued, or terminated either request of any interested person (including the permittee) or upon the director's initiative. The term "interested person" is not defined in the federal regulations (or other state regulations). The term encompasses any person who expresses an interest in an application, permit, or Class VI UIC well. However, the language in §5.202(d)(1) seems to equate "interested person" with "affected person." The term "interested person" is broader than the term "affected person" and the federal regulations at 40 CFR §124.5 allow any interested person to request a review of a permit. Therefore, the Commission adopts §5.202(d)(1) with a change removing the examples of those who qualify as an interested person. The Commission notes, however, permits may only be modified, revoked and reissued, or terminated for the reasons specified in 40 CFR §144.39 or §144.40.

The Texas-based organizations requested clarification of §5.202(d). The organizations recommended that the Commission revise paragraph (1)(B) to be inclusive of any agencies that have jurisdiction over groundwater research or policies at the state or local level. They also recommended that the Commission revise paragraph (1)(C) to include any person who "may" suffer injury or economic damage. The threshold for participation by the public should be inclusive of all who may be potentially impacted, rather than overly narrow and restrictive. Requiring a burden of proof on poorly-resourced individuals to prove that they "will" be impacted in order to qualify as an "interested person" is unreasonable.

The Commission will establish a procedures to allow interested persons to sign up to be notified. If an interested person submits a comment or requests a hearing, the Commission will automatically add that person to the mailing list. The Commission made no change in response to this comment.

The Texas-based organizations noted that §5.202(d)(2)(A)(vii) states "During any revocation and reissuance proceeding the permittee shall comply with all conditions of the existing permit until a new final permit is reissued." This implies that when a facility permit is revoked, the facility may be allowed to continue operating while a new permit application is being processed. The Texas-based organizations ask: if a facility has operated in a manner that justifies revoking the permit and which causes risk of injury or actual injury to its neighbors or the surrounding community, in which cases would the Commission stop the facility from continuing to operate?

The Commission makes no change in response to this comment. The section to which the comment refers concerns instances in which the Commission has determined that the permit should be revoked and reissued, such as when there are material and substantial alterations or additions to the permitted facility or activity which occurred after permit issuance that justify the inclusion of permit conditions that are different from or absent in the existing permit; or the director has received information that was not available at the time of permit issuance and would have justified the inclusion of different permit conditions. Examples may include any increase greater than the permitted CO_2 storage volume, and/or changes in the chemical composition of the CO_2 stream; the standards or regulations on which the permit was based have been changed by promulgation of new or amended standards or regulations or by judicial decision after the permit was issued; or the director determines good cause exists for modification of a compliance schedule, such as an act of God, strike, flood, or materials shortage, or other events over which the permittee has little or no control and for which there is no reasonably available remedy. This provision is separate from termination of a permit.

TXOGA and TIP identified certain issues with §5.202(d), which generally addresses causes for permit modification, revocation, reissuance, or termination. First, TXOGA and TIP recommended that the Commission revise §5.202(d)(2)(A)(ii) to require that the threshold for permit modification or for revocation and reissuance be based on new information that must be material.

Second, TXOGA and TIP recommended that the Commission revise §5.202(d)(2)(A)(iii) to include language that a new regulation that may cause a modification or a revocation and reissuance of a permit should be based on a new, material change to applicable standards or regulations. This is generally consistent with the type of modification contemplated by the federal equivalent of this section, found in 40 CFR §144.39(a)(3).

The Commission agrees with these comments and adopts §5.202(d)(2)(A)(ii) and (iii) with the recommended changes.

TXOGA and TIP requested clarification on how the provisions on causes for modification, revocation and reissuance, or termination in §5.202(d)(2) will operate in practice given the Commission's incorporation by reference of EPA regulations in whole or in part in this proposal. TXOGA and TIP have concerns that any change in EPA regulations could potentially serve as an automatic basis for a permit modification, revocation and reissuance, or termination. One way to address this would be to state in the rules that the federal regulations would be incorporated as issued on a certain date, and any subsequent federal regulatory change would be subject to the Commission's rulemaking process to maintain appropriate opportunities for notice and comment to the rule changes.

The Commission made no change in response to this comment. One of the causes for modifications or for revocation and reissuance of a permit under §5.202(d)(2)(A)(iii) is that the "standards or regulations on which the permit was based have been changed by promulgation of new or amended standards or regulations or by judicial decision after the permit was issued." In §5.201(e), the Commission adopts by reference 40 CFR §144.7 and §146.4 relating to expansion of aquifer exemption, effective September 20, 2022, and in §5.201(f), the Commission adopts by reference 40 CFR §146.95, effective September 20, 2022. If the federal regulations are amended, the Commission will readopt those subsections in a rulemaking process consistent with the Administrative Procedures Act.

TXOGA and TIP requested that the Commission include a materiality standard for permit modification triggers that would allow minor modification changes to be made in a streamlined process, consistent with the federal equivalent in 40 CFR §144.39.

The Commission notes that §5.202(d)(2)(A)(viii) includes the list for permit modification triggers that would allow minor modifications on a streamlined basis consistent with 40 CFR 144.39. However, the Commission adopts the provision with a change to add "minor" before "changes" to clarify that the enumerated changes are considered minor.

The Texas-based organizations expressed concern that the director has the ability to modify a permit with only the permittee's consent and without following notice and public comment period requirements for many reasons that the public would ordinarily need to provide feedback on.

The Commission disagrees. The listed changes for which the permit can be modified with only the permittee's consent are minor modifications that are allowed under the federal regulations at 40 CFR §144.41.

EAC and Denbury recommended that to ensure regulatory certainty the Commission define what qualifies as a change in the chemical composition of the CO_2 stream as a cause for permit modification. These commenters stated that if the CO_2 stream is supplied by numerous captured emission sources, there is a potential for minor or insignificant fluctuations in CO_2 stream composition to occur as the volume delivered by the various emitters fluctuates and as new emitters are added to the system. While the commenters do not believe the Commission intended for such minor fluctuations to constitute a "change", they recommended that the Commission include a reasonable threshold of molar percentage change in chemical composition before the Commission would require consideration of a permit modification.

Similarly, TXOGA and TIP request that the Commission acknowledge that different emitters may alter the carbon dioxide composition in the pipeline and that pipeline criteria may also impact carbon dioxide composition. TXOGA and TIP requested clarification on what might qualify as a sufficient modification of the volume or chemical composition of the carbon dioxide stream.

The Commission understands that the types of impurities and their concentrations will vary by generator and pollutant removal and carbon capture technologies. In addition, the Commission understands that different entities may alter the carbon dioxide stream composition in the pipeline and that pipeline criteria may also impact carbon dioxide stream composition. Furthermore, it may be necessary to add substances to the carbon dioxide streams to improve injectivity, including substances to reduce viscosity, inhibit reactions with brine or formation rocks, or otherwise improve permeability. Any addition of substances to carbon dioxide streams to enable or improve the injection process would be occurring as part of the UIC Class VI permitted activity and thus ultimately implemented in a manner to prevent the endangerment of USDWs.

The rules require that the chemical composition and physical characteristics of the carbon dioxide streams be known as part of the initial permitting process, as well as during operation of the well, to ensure that these carbon dioxide streams can be injected in a manner that is protective of human health and the environment and USDWs. The rules address the quality and quantity of impurities by requiring operators to submit information on the source of the carbon dioxide and its physical and chemical properties. Specifically, the rules require the operator to submit data about the site, including an analysis of the chemical and physical characteristics of the carbon dioxide stream and information on the compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in both the injection and the confining zones and the materials used to construct the well. This information can help the director determine the potential for geochemical reactions between the injectate (the carbon dioxide stream) and the host geologic formations, which could result in the plugging of pore spaces or the dissolution of formation minerals. Analysis of the carbon dioxide stream will provide information about any impurities that may be present and whether such impurities might alter the corrosivity of the injectate down-hole. Such information is necessary to inform well construction and the project-specific testing and monitoring plan and enable the operator to optimize well operating parameters while ensuring compliance with the Class VI permit. The analysis of the carbon dioxide stream must be conducted prior to commencing injection and throughout injection operations at an appropriate frequency based on the source of the carbon dioxide stream and the likelihood of variability in the injectate composition. The details of the sampling process and frequency must be described in the director-approved, site-specific testing and monitoring plan.

Neither the federal rules nor the Commission’s rules set generic purity standards for carbon dioxide injectate streams (e.g., a percent carbon dioxide). The injection of carbon dioxide streams, including incidental associated substances derived from the source materials and the capture process, can be performed in a protective manner at a permitted UIC Class VI well. Regardless of the precise contaminants, and their concentrations, the UIC Class VI permitting requirements will take into account the physical and chemical characteristics of the carbon dioxide stream as part of establishing the appropriate conditions for the successful confinement of the carbon dioxide in a manner that is protective of USDWs.

However, the Commission agrees that some threshold for determining the need to modify the permit would be appropriate. Therefore, the Commission adopts a clarifying change in §5.202(d)(2)(A)(ii).

TXOGA and TIP understand that proposed §5.202(d)(2) and §5.204(b) are referencing an opportunity for a public hearing, if warranted, and that a public hearing is distinct from a contested case hearing that is otherwise provided for under Commission rules in 16 TAC Chapter 1. TXOGA and TIP suggest that for consistency, references to a "hearing" be revised to "public hearing" throughout the rule text, as appropriate, along with corresponding revisions to preamble references as well.

The Commission declines to make a change in response to the comment. The references to a hearing in §5.202(d) and §5.204(b) mean a contested case hearing.

Texas 2036 commented that proposed §5.202(e)(2) requires that the Oil and Gas Division director prepare a fact sheet for each draft permit that includes a description of the proposed facility and quantity of CO_2 planned for injection and storage. This fact sheet would be made available to the permit applicant and, upon request, to any other person. The fact sheet shall also be included as part of the public notice for each permit application. Texas 2036 recommended that the fact sheet also include a description of the proposed source, or sources, of CO_2 for a CCUS project. Examples of potential sources could include electric generation facilities, manufacturing facilities, hydrogen generation facilities, or even direct air capture. Given that the fact sheet is a public document for each permit application, and included as part of the public notice provided under §5.204(a), Texas 2036 believes it should include a disclosure regarding potential sources of CO_2. If a proposed facility is planned to capture CO_2 from a specific source, then that is a material disclosure that should be made available early in the permitting process. This disclosure would enhance the transparency for each permit application while helping advance the policy argument for each proposed CCUS facility. Amending the fact sheet disclosure requirements in §5.202(e)(2) to require the description of the proposed CO 2 source(s) would achieve this result. Texas 2036 notes that 26 USC §45Q provides a sequestration tax credit for the capture and disposal of "qualified carbon dioxide," which includes CO_2 captured from an industrial source. Just as permit applicants would need to identify the source of their "qualified carbon dioxide" in order to qualify for a §45Q sequestration credit, they should be able to identify that source in their permit application.

The Commission agrees and adopts §5.202(e)(2)(C)(ii) with a change to require the source of CO_2 to be included in the fact sheet.

Texas 2036 commented that the proposed rule states that the fact sheet shall be made available to any other person upon request. In the interest of enhancing the transparency of this critical Commission program, Texas 2036 recommended that the Commission make the fact sheets for proposed CCUS facilities publicly available on the Commission's website.

The Commission agrees and adopts §5.202(e)(2)(B) with a change to address this comment.

§5.203

An individual recommended that the Commission work with EPA to provide clearer guidance regarding exactly what data and information operators must submit to EPA through EPA's Geologic Sequestration Data Tool (GSDT). Once a state obtains primacy, it should not be necessary for a permit applicant to submit to EPA every response to the Commission's requests for additional information or revision of the permit application. It should be sufficient to submit the final complete permit application and associated data.

The Commission makes no change in response to this comment. The federal regulation in 40 CFR §146.91(e) states that regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part (relating to Criteria and Standards Applicable to Class VI Wells) to EPA in an electronic format approved by EPA. In addition, the EPA's GSDT will assist the Commission in organizing and retaining the large volume of material related to permit application reviews and subsequent project oversight activities. The EPA's GSDT facilitates compliance with the electronic reporting requirement in 40 CFR §146.91(e), providing reporting modules by which permit applicants/owners or operators can submit required information in an approved electronic format, and supports permitting authorities in tracking and managing submissions associated with Class VI reporting, including support for evaluation and oversight activities over the duration of a Class VI project.

PBPA recommended that §5.203 generally allow alternative methods that are approved by the director to provide greater flexibility in changing environments.

The Commission disagrees that greater flexibility is needed. States are required to apply for primacy for the Class VI UIC program under Section 1422 of the federal SDWA. Under that section, Texas must demonstrate that the State program meets EPA's minimum federal requirements. Those federal requirements, and the Commission's rules, include some flexibility, but a general authorization to allow alternative methods approved by the director would result in a program that does not meet the minimum federal requirements.

Section 5.203(a)(2)(D) requires that all applicants obtain letters of determination from TCEQ prior to being issued a permit by the Commission. Understanding that HB 1284 and Texas Water Code Section 27.0461 require this TCEQ determination, TXOGA and TIP requested greater detail and information on the framework for that two-step process and related timeframes for TCEQ and Commission coordination.

The Texas-based organizations also requested clarification regarding the kind of geospatial information applicants be required to provide the TCEQ so that the TCEQ can make its determination. Will the geographic coordinates of such data be required to be accurate within a certain measurement (for example, five feet)? The organizations commented that it is important to determine the accuracy of geospatial data that TCEQ will be using to determine the locations of both proposed Class VI wells and previous or existing Class I injection wells and their plumes.

The Commission notes that the TCEQ must have sufficient information to make the required determination. TCEQ staff has access to the information filed through EPA's GSDT online system. Using that information, TCEQ will perform the required evaluation and draft the required letter of determination. The TCEQ letter of determination is required before the Commission can issue authority to construct the injection well.

The Texas-based organizations recommended that the Commission require TCEQ's letter to verify that the Class VI well will not impact or interfere with wells "required to be authorized" by TCEQ, whether or not such wells are authorized.

The Commission does not understand this comment. Section 5.203(a)(2)(D) (D) requires a person applying for a permit under this subchapter to submit 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. TCEQ consideration of a well that is required to be authorized but is not authorized would imply that TCEQ has knowledge of such a well.

An individual expressed concern that the rules do not require a professional geoscientist or a professional engineer to review and approve the design of a sequestration facility. The proposed rules allow operators to self-certify their proposed design complies with the applicable regulations.

The Commission made no change in response to this comment but notes §5.203(a)(5) states that, if required under Texas Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscience Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required and must affix the appropriate seal on the resulting reports of such evaluations.

The GLO recommended that reservoir data requirements include both the injection zone and the confining zone consistent with Texas Class I regulations to manage and protect the integrity of the storage reservoir.

The Commission notes §5.203(c) requires an applicant for a carbon dioxide geologic storage injection well permit to submit geologic, geochemical, and hydrologic information on all relevant geologic formations, including the storage reservoir, the confining zone and formations overlying these zones. The Commission made no change in response to this comment from the GLO.

The Texas-based organizations commented that subsection (c)(2)(G) requires applicants to submit "baseline geochemical data" for subsurface formations. The organizations requested clarification as to whether such data will include baseline groundwater quality data. If so, which types of chemicals or analytes must be included in the baseline data? For example, should applicants submit test results for salts, radionuclides, metals, volatile organic compounds (VOCs), and Polycyclic Aromatic Hydrocarbons (PAHs)? Which constituents of each category should applicants test for? Other considerations include how often and how many tests should be taken in advance of well construction to establish baseline conditions. Similarly, the Texas-based organizations commented that it is advisable to take samples both upgradient and downgradient of the proposed injection well.

The Commission makes no change in response to this comment but notes the following. The rule requires baseline geochemical information on subsurface formations including all USDWs in the AOR. Geochemical information on both solids and fluids is also needed, in combination with the mineralogic data required, to determine whether the interaction of the formation fluids with the injectate and solids will cause changes in injectivity, changes in the properties of the confining zone, or the release of trace elements. Background information will also allow operators to distinguish possible effects of injection from naturally occurring variations over the life of the project.

The specific parameters to be analyzed will depend on the characteristics of the site, each formation being analyzed, and the composition of the planned CO_2 stream. Analyses should include basic parameters, such as pH; total dissolved solids (TDS); alkalinity; specific conductivity (SC); and major anions and cations (e.g., Ca2+, Mg2+, K+, Na+, Cl-, Br-, SO42-, and NO3-). Other constituents may differ by formation and be determined based on the mineralogy of the injection and confining formations. These may include: Sr2+, Fe2+, Fe3+, Al, SiO2, total organic carbon (TOC), and hydrogen sulfide and trace metals. Additionally, baseline gaseous carbon dioxide should be measured in subsurface formations including all USDWs within the AOR. Samples from proposed injection zones that are depleted hydrocarbon reservoirs may need to be analyzed for hydrocarbons.

In addition, common practices for groundwater monitoring would include monitoring of water both upgradient and downgradient of the injection well.

The Texas-based organizations recommended that the Commission revise the rules to require that the completion report required to be filed after the completion or conversion of an injection well subject to this subchapter also include the latitude and longitude coordinates of the wellbore within a specified accuracy.

The Commission notes the Completion Report (Form G-1 and W-2) requires the well latitude and longitude to a minimum five decimal places and the type. The Commission made no change in response to this comment.

PBPA recommended that the Commission revise §5.203(e)(1)(B)(ii) to allow operators to integrate standards that achieve equal results based on reservoir characteristics.

The Commission does not agree that §5.203(e)(1)(B)(ii) (relating to casing and cementing of anthropogenic carbon dioxide injection wells) needs to be revised to allow operators to integrate standards that achieve equal results based on reservoir characteristics. The last clause in §5.203(e)(1)(B)(ii) allows "comparable standards as approved by the director."

Regarding §5.203(e)(1)(B)(ii), TXOGA and TIP requested that chrome tubulars not be included as a requirement. Years of EOR experience in the Permian Basin demonstrates that other types of tubulars can be used successfully when paired with other mechanical means of corrosion inhibition. Further, chrome tubulars are not a requirement for CO_2 flooding, and §5.203(e)(1)(B)(vii) notes that the director may exempt existing wells from the requirements of this section.

The Commission made no change in response to this comment because the rules do not specifically require chrome tubulars.

The GLO recommended that the Commission revise the rules to require that cementing be verified by surface circulation. The proposed rules would allow operators to calculate or otherwise estimate the quantity of cement being used to protect USDW and the storage reservoir through alternative methods. Such methods ostensibly include purely volumetric calculations and the use of indirect log evidence. The GLO believes none of these alternative methods is consistent with Texas Class I regulation and they create unnecessary risk because lost circulation while drilling or other anomalies can result in insufficient cement coverage or bonding.

The Commission partly agrees with this comment. Section 5.203(e)(1)(B) requires that surface casing be cemented to the surface. The federal regulations at 40 CFR §146.86(b)(3) require that at least one long string casing, using a sufficient number of centralizers, be cemented by circulating cement to the surface in one or more stages. However, §5.203(e)(1)(B)(v) does not make it clear that the long string must be cemented to the surface as required by federal regulations. The Commission adopts §5.203(e)(1)(B)(v) with a change to ensure consistency with the federal regulation in 40 CFR §146.86(b)(3). Consistent with the federal regulations at 40 CFR §146.86(b)(4), §5.203(e)(1)(B)(iv) allows circulation of cement by staging and authorizes the director to 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. Section 5.203(e)(1)(B)(vi) requires the applicant to 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.

EDF expressed doubts as to whether the Commission's exception process for transitioned wells in §5.203(e)(1)(B)(vii) is consistent with the requirements of 40 CFR at §146.86 for Class VI wells. Any exceptions granted for well construction and operation must be granted in a way that is consistent with the EPA's Class VI requirements. Additionally, EDF suggested the Commission consider broadening this provision to apply to Class I, Class II and Class V wells that transition to Class VI.

An individual also commented on §5.203(e)(1)(B)(vii). The individual noted that the proposed provision allows the director to exempt existing wells that have been associated with injection of CO_2 for the purpose of enhanced recovery 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. The individual recommended that the Commission not limit this provision to conversion of Class II enhanced recovery wells, as other wells may also be converted to Class VI wells if the wells meet the requirements of subparagraph (A).

The Commission agrees in part. The Class VI rule allows for the repermitting of an existing well as a Class VI well, provided the operator can demonstrate to the director that the well under consideration was engineered and constructed to meet the requirements of 40 CFR §146.86(a) and ensure protection of USDWs, in lieu of requirements at 40 CFR §146.86(b) and §146.87(a). The language in §5.203(e)(1)(B)(vii) is consistent with that requirement. Texas statutes prohibit the Commission from permitting an existing Class I UIC well. The Commission agrees that the requirements could use additional clarification and adopts §5.203(e) with changes to ensure the language is not too limiting.

WSP recommended that the Commission revise the language to not be limited to a "mechanical packer." Modification of the language would give the operator the ability to use the correct packer for the situation, be it a hydraulic or mechanical packer.

The Commission agrees. The federal regulations at 40 CFR §146.86(c) only require a packer and do not specify that the packer be mechanical. The Commission adopts §5.203(e)(1)(C)(i) with a change to remove "mechanical."

The Texas-based organizations and an individual expressed concern that the rules make it too easy for operators to use a Class II well primarily for carbon dioxide storage, without the same level of scrutiny and standards for Class VI construction. The commenters believe this creates an incentive for operators to apply for Class II permits, then convert Class II EOR wells to Class VI wells. The organizations commented that it is important to keep careful watch over the possibility of unscrupulous operators in the case of carbon dioxide injection. Carbon dioxide is a colorless, odorless gas and has a tendency to sink into low-lying areas, causing risk of asphyxiation and death. The organizations requested that the Commission consider that some operators will apply for a Class II permit while intending to take part in Class VI operations.

Similarly, the GLO commented that the Class II UIC program is inadequate for managing carbon sequestration wells. The rules appear to provide several pathways intended to allow use of the Class II UIC program to regulate carbon sequestration wells under various conditions. Existing federal Class VI guidelines are most similar to Class I industrial waste injection well guidelines. Use of the Class II program as a substitute for geologic carbon sequestration also begs the question, why does the existing federal Class VI regulatory program not contemplate such “upgrades’? A new fit-for-purpose class of UIC regulation was designed because it is needed to ensure the safe and consistent operations of GS facilities. Thus, the GLO believes the delegation should implement the Class VI practices required under federal law, rather than attempting to circumvent them.

Further, the GLO noted that carbon sequestration activities conducted using sources of high-acid hydrocarbon gas will not necessarily be small operations. Two of the world’s largest carbon sequestration projects (Sleipner in Norway and In Salah in Algeria) inject acid gas for geologic storage. The In Salah project has been shut down permanently due to the evolution of increasing carbon containment loss risks. Well integrity was a particular problem at In Salah, which highlights the need for high quality construction standards. Mechanical failures which limit maximum injection reservoir pressure will reduce its practical storage capacity, and less capacity means less revenue for the storage facility owner. This means that the PSF could lose significant revenue-generating opportunities even if actual containment of the injected fluid is not jeopardized, because permitted injection quantities will have to be curtailed.

The GLO commented that “long-term” in this context is at least 1000 years. Simulations of 1000 years of CO_2 injection into wells specifically designed for sequestration at the Ketzin pilot site in Germany showed that, if reservoir pressures remained elevated over the entire sequestration period, saturation of well cements with carbon dioxide and possible containment loss through the wellbores to the surface could occur. The study assumed that pressure would not quickly dissipate post-injection. The CO_2 saturation of the well cement caused its permeability to increase to a level enabling CO_2 migration. Significant corrosion of casing materials was also observed in the simulations. The GLO noted further studies have shown that the ability of the well cement to withstand carbonic acid attack is sensitive to the temperature and pressure of initial cement curing, the composition of the cement and any additives, and the pressure, temperature and pH of the carbon-rich brine environment to which cement is exposed. Older wells not originally designed for carbon sequestration service will not generally have been constructed from materials optimized for carbonic acid resistance.

The Commission agrees that the Class II UIC program is not appropriate for geologic storage of large volumes of carbon dioxide. The Commission disagrees that corrosion-resistant materials and cement do not exist. Experience over many decades in corrosive down-hole situations such as acid gas injection and production of natural gas with carbon dioxide and hydrogen sulfide shows that materials are available that can resist corrosive environments. Meyer (2007) lists several types of cements that have been used under such corrosive conditions. There are two studies of wells that were exposed to carbon dioxide for approximately 30 years by Carey et al. (2007) and Crow et al. (2008). Although these studies are limited in the number of well material samples and the number of wells examined, the casing and cement sampled indicate fairly good condition of well materials installed three decades ago. The director will carefully review information provided by the applicant to determine whether proposed casing and cementing materials will be adequately resistant to corrosion for each geologic storage project.

Both EPA and the Commission recognize that the Class II UIC program has managed acid gas disposal and injection of carbon dioxide for enhanced recovery for upstream oil and gas activities for decades. The Commission also recognizes that the injection and storage of larger volumes of carbon dioxide has the potential for increased risk to USDWs. The Commission has indicated in its rules that this potential for increased risk will be considered when determining whether a Class II UIC well should be transitioned to a Class VI UIC well.

As the commenter stated, simulations of 1000 years of carbon dioxide injection into wells specifically designed for sequestration at the Ketzin pilot site in Germany showed that, if reservoir pressures remained elevated over the entire sequestration period, saturation of well cements with carbon dioxide and possible containment loss through the wellbores to the surface could occur. The study assumed that pressure would not quickly dissipate post-injection. The Commission finds that pressure dissipation is an important part of selecting an appropriate site and reservoir for the injection and storage of carbon dioxide. If modeling of a proposed project or monitoring of a permitted project reveals that pressure is not dissipating such that USDWs are threatened, the Commission will not approve a proposed project or will require cessation of injection in a permitted project.

In addition, §91.801 of the Texas Natural Resources Code requires the Commission to adopt rules that allow an operator of a well authorized by a permit issued by the Commission to convert the well from its authorized purpose to a new or additional purpose.

The Commission made no changes in response to these comments.

The Texas-based organizations requested clarification as to how the Commission will monitor Class II wells to verify that operators are not simply applying for Class II permits while they are primarily operating a geologic storage facility for anthropogenic carbon dioxide.

The Commission notes that §5.201(b)(2) lists the factors that the Commission will consider in determining if there is an increased risk to USDWs. These include an increase in reservoir pressure within the injection zone; an increase in carbon dioxide injection rates; a decrease in reservoir production rates;

the distance between the injection zone and USDWs; suitability of the enhanced oil or gas recovery AOR delineation; the quality of abandoned well plugs within the AOR; the storage operator's plan for recovery of carbon dioxide at the cessation of injection; the source and properties of injected carbon dioxide; and any additional site-specific factors as determined by the Commission. The Commission is monitoring existing operations and carefully reviewing any applications for new Class II injection wells proposing to inject carbon dioxide using these factors. The Commission made no change in response to this comment.

The Texas-based organizations expressed concern that operators have falsified production reports to appear as though their wells meet the definition of active status and have continued to produce after receiving a seal and sever order. They recommended that the Commission collect real-time production and injection data from well operators to more accurately monitor Class II operations.

The Commission realizes the possibility that an operator could falsify production and injection data. The Commission’s reporting and inspection requirements assist the Commission in determining whether data has been falsified. In addition, §85.387 of the Texas Natural Resources Code provides that a person shall be imprisoned in the Texas Department of Criminal Justice for not less than two nor more than five years if the person knowingly procures or causes an agent, officer, or employee of the Commission to approve or issue a permit or tender of the Commission relating to oil or gas or any product or by-product of oil or gas that includes a statement or representation that is false and that materially misrepresents the true facts respecting the oil or gas or any product or by-product of either. The Commission made no change in response to this comment.

Regarding §5.203(f)(1), TXOGA and TIP requested clarification as to whether alternative logs and derived curves would be acceptable if applicable or necessary. They also requested clarification with respect to the geologic logs which must be run in advance of long string casing installation, and whether the Commission is referring to formation imaging logs (fmi) or other log types.

Section 5.203(f) lists the general type of appropriate logs that must be run and provides examples of such logs. As stated, the logs must 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. With respect to geologic logs that must be run 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. Formation imaging logs are not specifically mentioned but may be useful to provide detailed information about the rocks in formations surrounding an open hole and about the pipe and casing condition in cased holes. The Commission made no change in response to this comment.

TXOGA and TIP request clarification that §5.203(f)(2)(B) assumes that a nearby well is accessible to perform a pressure fall-off test, and information on the minimum requirements for the coring and analysis required by §5.203(f)(3)(B).

The Commission made no change in response to this comment but clarifies as follows. Section §5.203(f) requires plans for logging, sampling, and testing of injection wells after permitting but before injection. Therefore, the assumption in this section is that the injection well has been drilled and completed. However, information on reservoir pressure response is required in the initial application possibly before the injection well has been drilled and is required to model the AOR. Therefore, the applicant may perform testing on nearby wells or a stratigraphic test well as long as the applicant can demonstrate that such data are representative of conditions at the proposed injection well.

The Texas-based organizations requested clarification of §5.203(f)(2)(C) as to whether 90% of fracture pressure is adequate to prevent initiation of new fractures or propagate existing fractures. They also requested clarification as to how this will be monitored. The Texas-based organizations asked for clarification as to why the rules allow the director to approve a plan "for controlled artificial fracturing" when this paragraph is trying to prevent fractures.

The Commission notes its regulations are consistent with the federal regulations, which only prohibit fracturing of the confining zone. The director may approve a plan for controlled artificial fracturing of the injection zone. The safety factor of 90% of fracture pressure is adequate to prevent initiation of new fractures or propagation of existing fractures in the confining zone. Therefore, except during approved stimulation activities, injection pressure may not be greater than 90 percent of the fracture pressure of the injection zone. However, the Commission adopts §5.203(f)(2)(C) with a change to clarify these requirements. The Commission plans to be on-site during testing required to determine fracture pressure and during any planned stimulation activity.

TXOGA and TIP recommended that the Commission specifically allow the use of chemical tracers for the confirmation of the absence of significant fluid movement into a USDW required by §5.203(h)(1)(D).

The Commission declines to make the requested change. The federal Class VI regulations require annulus pressure tests and monitoring to verify internal mechanical integrity. However, if written approval is received from the EPA Administrator, the director may allow alternative mechanical integrity testing methods. *See* 40 CFR 146.89(e). Currently, the only available alternative internal MIT is the radioactive tracer survey, which is used under specific conditions (USEPA. 1987b. Underground Injection Control Program: Radioactive Tracer Survey Approval. Federal Register, Vol. 52, No. 237, p. 46837). The radioactive tracer survey may require long periods of investigation and cannot feasibly be conducted continuously during injection (and therefore cannot be used to comply with the continuous monitoring requirements). However, the radioactive tracer survey can provide supplementary information regarding internal fluid leakage and therefore may be conducted in addition to annular pressure monitoring. The radioactive tracer survey may be used to locate the depth of a leak within the well bore, unlike annulus pressure tests.

The Class VI rule in 40 CFR §146.89(c) requires that an oxygen-activation log or other approved tracer survey, a temperature log, or a noise log be conducted to comply with external mechanical integrity testing requirements. However, under 40 CFR §146.89(e), alternative methods beyond those listed may be allowed by the director if written approval is received from the EPA Administrator. Title 40 CFR §146.89(e) also states that a request to use methods other than those currently approved by EPA requires EPA approval and publication of the alternative method's approval in the *Federal Register*. Currently, there are no alternative methods that may feasibly be used for external mechanical integrity testing beyond those listed, except under very limited circumstances.

EPA's guidance on testing and monitoring indicates that radioactive tracer surveys have been used for assessing external mechanical integrity. Use of radioactive tracer surveys as the sole test for external mechanical integrity testing is limited to cases where there are no permeable formations between the injection zone and the lowermost USDW (USEPA. 1987b. Underground Injection Control Program: Radioactive Tracer Survey Approval. Federal Register, Vol. 52, No. 237, p. 46837). Essentially, a single confining layer would need to be present that separates the injection zone from the lowermost USDW. Given the depths of Class VI wells and the significant siting requirements, it is unlikely that this condition will be met for Class VI wells.

The Texas-based organizations commented on subsection (j) and requested clarification of internal processes the Commission will follow to verify that operators are conducting their plan for monitoring, sampling, and testing, as approved. The Texas-based organizations recommended that the Commission adopt a clear process of how permits will be monitored and enforced and a clear grievance process when the agency's monitoring and enforcement is in question.

Commission staff will not issue a permit that does not meet the requirements of Chapter 5, Subchapter B. Staff will review Class VI facilities for compliance at least annually. Compliance will be determined through review of records submitted by the facility operator, the facility permit, the permit application, and the rules. If staff finds that the operator has not submitted records to demonstrate compliance, the operator will be notified that they are in violation and must come into compliance or enforcement action will be pursued. Any report of a violation of a Commission permit will be evaluated, investigated, and enforced, if necessary. Lastly, any person may file a complaint under 16 TAC §1.23, which requires the respondent to answer the complaint or request a hearing within 20 days. The Commission made no change in response to this comment.

TXOGA and TIP request that the Commission consider adding language allowing for alternative methods to the pressure fall-off test to be used if approved by the director in §5.203(j)(2)(F).

The Commission declines to make the requested change because the federal rules require pressure falloff testing and provide for no alternative.

The GLO recommended that the Commission revise the rule language to require an annual pressure falloff test rather than requiring the test once every five years consistent with the Class I requirements. The GLO commented that the computational reservoir models used to monitor, verify, and quantify carbon storage are extremely sensitive to input data, including permeability, pressure, and the locations of reservoir boundaries, that are all routinely obtained or calibrated against falloff test interpretations. Moreover, falloff test results can signal increases in reservoir pressure that could lead to fracturing of the injection or confining zone, and to loss of containment. The tests can also help to detect the changing transmissivity or sealing potential of faults over time. The Miocene reservoirs are heavily faulted, and knowledge of the dynamic sealing potential of isolated reservoir compartments must inform decisions about the number, location, and size of carbon storage repositories offered for lease by the GLO.

The Commission made no change in response to this comment. The federal Class VI regulations require pressure falloff testing every five years. The Commission's rules allow the director to require more frequent testing and the Commission agrees that it would be helpful to know how the reservoir is performing at the beginning of injection. Therefore, the Commission may require more falloff testing at the initiation of injection and for a period after initiation of injection. In addition, in a reservoir that is heavily faulted, more frequent testing might be appropriate. However, testing at that frequency may not be necessary for the life of the project.

The Texas-based organizations expressed concerns regarding the accuracy of the AOR, considering that the latitude and longitude coordinates for many wells in the Commission's database are either not available or are inaccurate. One of the criteria the director may use to determine if a Class II well poses an increased risk to USDWs includes the "quality of abandoned well plugs within the AOR." Currently, the Commission's orphaned well list contains over 350 wells with no latitude or longitude coordinates and there are over 1,700 inactive unplugged wells with active operators and no latitude or longitude coordinates. Some landowners have reported undocumented wells on their properties that are unplugged and show evidence of having been drilled as oil and gas wells. The organizations requested clarification as to whether the Commission will consider better locating existing wells of all types so that AORs can be developed that fully account for potential risks.

The Commission notes that the rules require an applicant to identify all penetrations in the AOR that may penetrate the confining zones. The Commission agrees that a variety of types of abandoned wells may exist within the delineated AOR of a proposed project, including wells constructed prior to federal or state regulation (i.e., in the late 1800s or early 1900s), for which the Commission may have little or incorrect location information. However, several methods and sources of information are available to identify those artificial penetrations in a relatively efficient manner. The primary stages of an abandoned well investigation within the AOR include historical research, site reconnaissance, review of aerial and satellite imagery, and one or more geophysical surveys. Applicants will be required to conduct a records review as the first step in abandoned well identification within the AOR. Such records may include state databases or other files, county records, including survey maps, ownership records, and chain-of-title and property lease history, maintained by local tax assessors and county clerks, private data compilation service records. Such research may also include site reconnaissance, including interviewing local residents and property owners, oilfield workers, service company employees, and property and drilling-rights ownership brokers, as well as conducting a physical search for features indicative of abandoned wells. An applicant may also use historical aerial photographs to identify abandoned wells. Depending on the resolution of the image, satellite images may be used. Surface features may indicate abandoned wells including abandoned well derricks, access roads, brine pits, or vegetation stress. In addition, geophysical surveys, including magnetic, ground penetrating radar (GPR), and electromagnetic methods, can be used in the detection of abandoned wells in the AOR. The Commission made no change in response to this comment.

PBPA expressed concern that the post closure requirements in §5.203(m) would be completed during permitting, where it is more appropriate that the demonstrations be broadened to include post injection scenarios as well.

The Commission notes the requirements are consistent with the federal rules, which require that a post-injection storage facility care and closure plan be submitted with the application. The approved plan is a requirement of the Class VI permit. It is not unusual to include closure requirements in permits. In addition, the post-injection storage facility care and closure plan must be prepared in order to ensure that financial assurance will cover the estimated costs of post-injection care and closure, which is required to be submitted with the application.

Because operators at certain geologic storage sites will be able to demonstrate long-term containment and non-endangerment to USDWs before the end of the default 50-year monitoring period, TXOGA and TIP support the post-closure monitoring, which is reflected in the additional criteria language contained in §5.203(m). TXOGA and TIP additionally request clarification on whether, if the demonstration requirements are not met, the default 50-year monitoring period would be required or whether monitoring would continue until the demonstration is effectively made. Furthermore, TXOGA and TIP request that the Commission clarify that this demonstration can be made during permitting or post injection periods.

Monitoring must continue until the permittee can make the demonstration required before closure. The demonstration must be performed after injection ceases. The Commission made no change in response to these comments.

An individual recommended that the Commission not adopt a 50-year default period for PISC and use instead agreed criteria for demonstrating non-endangerment of USDWs. Experience shows that reductions in pressure and fluid movement within storage reservoirs are likely to occur much sooner than the 50-year period. In unusual cases where such demonstrations take longer, the current regulatory language already allows that even without specification of the default period. Estimates to support FA should be based on more realistic projections. The default 50-year PISC period is longer than it needs to be for well-chosen sites, and more flexibility should be included in Class VI permits so that shorter PISC timeframes can be specified with possibility of adjustment depending on actual site conditions.

The Commission appreciates this comment.

The Texas-based organizations recommended that the Commission not allow alternative timeframes for monitoring that are less than 50 years because carbon dioxide lasts tens of thousands of years in the atmosphere and wells get more dangerous as they age. The state should not prematurely take on responsibility for inactive assets that are likely to eventually fail.

The GLO recommended that the Commission's rules retain the federal 50-year default post-injection site care monitoring because regular monitoring data is essential for reducing the uncertainty of reservoir models used to provide early warnings of containment loss or plume migration post-injection and because well cement degradation may occur over a period of several decades. Reduction of the monitoring or PISC period could create financial incentives for operators to design wells and ancillary equipment that have a shorter service life. Long-term monitoring will also help to mitigate against the possibility that latent errors will cause future damage to the facility that are not easily traceable to specific operational actions.

TXOGA and TIP requested clarification on the Commission's proposed addition to §5.203(d)(1)(A)(i)(III), and the preamble description of the requirement that "the initial delineation of the area of review must be estimated from initiation of injection until the plume movement ceases, for a minimum of 10 years after the end of the injection period proposed by the applicant." TXOGA, TIP, Denbury, and the EAC recommended that the Commission change the language in §5.203(d)(1)(A)(i)(III) to "until the plume movement *stabilizes*." Denbury and the EAC commented that Wyoming takes this approach and defines plume stabilization as being "achieved when the carbon dioxide stream that has been injected subsurface essentially no longer expands vertically or horizontally and poses no threat to

USDWs, human health, safety, or the environment, as demonstrated by a minimum of three consecutive years of monitoring data." TXOGA and TIP also requested that the Commission establish a time limit for this requirement to allow for greater modeling certainty.

The Commission notes the federal rules at 40 CFR §146.93, relating to post injection site care and site closure, require that the operator continue to conduct monitoring for at least 50 years following cessation of injection. However, the director may approve, in consultation with EPA, an alternative timeframe other than the 50-year default, if the operator can demonstrate during the permitting process that an alternative timeframe is appropriate and ensures non-endangerment of USDWs. The federal rules require that the demonstration be based on significant, site-specific data and information and contain substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the alternative post injection site care timeframe. Current Commission rules do not include a 50-year default post injection site care period. To meet the minimum federal requirements, the Commission proposed to amend §5.203(m) to include the data and information required to make a demonstration that an alternative timeframe is appropriate and ensures non-endangerment of USDWs. If the monitoring period is performance-based (i.e., no endangerment of Underground Sources of Drinking Water (USDWs)), a specific time frame is artificial.

The Commission considered the recommendation to replace the term "stabilization" as opposed to "cessation of movement" regarding plume movement. The final federal regulations do not include language regarding "plume stabilization." In fact, EPA removed a discussion of "plume stabilization" from one of its draft guidance documents as a result of comments it received. However, other states have included the concept of "plume stabilization." For example, Wyoming regulations require post injection site care monitoring for a period of not less than 10 years or as long thereafter as necessary to obtain a completion and release certificate certifying that plume stabilization has been achieved without the use of control equipment based on a minimum of three consecutive years of monitoring.

Because the goal of the Class VI UIC program is to prevent endangerment of USDWs, we agree that cessation of plume movement may not be the best measure. A plume can still be moving yet be considered non-endangering. Rather the plume and pressure front should not continue moving in a manner that increases the probability that it will encounter a leakage pathway. Complete stasis of the plume and pressure front within the injection interval as a requirement to end post injection site care monitoring could be unrealistic and unnecessary. The emphasis should be on documenting the effectiveness of the vertical separation and plume and pressure front confinement beneath adequate confining zones. If, to a high degree of certainty, the plume and formation fluids will remain deep in the subsurface below the confining zone, then any lateral migration may not result in endangerment of USDWs and it will be unnecessary for a plume or pressure front to be in complete stasis. The operator should be allowed to demonstrate that a plume and pressure front are not migrating vertically, with a trend toward pressure and chemical equilibrium.

Wyoming defines plume stabilization as being "achieved when the carbon dioxide stream that has been injected subsurface essentially no longer expands vertically or horizontally and poses no threat to USDWs, human health, safety, or the environment, as demonstrated by a minimum of three consecutive years of monitoring data." As such, Wyoming defines stabilization in terms of movement of the CO_2 stream. Therefore, it should not matter whether the Commission uses the term "stabilizes" or "ceases." However, Merriam Webster defines "cease" as "to come to an end or to bring an action or activity to an end," and defines "stabilize" as "to hold steady, such as to limit fluctuations of." The term "stabilize" appears to be more appropriate as it does not imply that the plume and associated pressure front must be in complete stasis. Due to these considerations, the Commission adopts §5.203 with changes in (d)(1)(A)(i)(III), (m)(5), and (m)(7)(iii).

EDF commented that it is important that the Commission's approach to the initial delineation of the AOR be consistent with what is needed in order to determine the length of PISC period and required period of monitoring, i.e. a determination of the point at which the plume has or is expected to be essentially stabilized. Accordingly, EDF recommended that the Commission delete the 10-year minimum from §5.203(d)(1)(A)(i)(III).

The Commission agrees with this comment. The Commission requested comment on whether the Commission should consider a minimum post injection site care monitoring period. Other states have included minimum PISC monitoring requirements. For example, Wyoming regulations require PISC monitoring for a period of not less than 10 years or as long thereafter as necessary to obtain a completion and release certificate certifying that plume stabilization has been achieved without the use of control equipment based on a minimum of three consecutive years of monitoring. Because the post injection monitoring period is to be based on individual projects and site-specific data, the Commission agrees with this comment and has made the recommended change in §5.203(d)(1)(A)(i)(III).

Regarding §5.203(e)(1)(B)(v)'s requirement for at least one long string casing to extend through the injection zone, TXOGA, TIP, EAC, and Denbury recommended changing the requirement from the long string "must extend through the injection zone" to the long string "must extend to the injection zone." This would allow for the potential use of a chrome liner to be run through the injection interval which could reduce cost and improve the quality of the cement job. The State of Wyoming uses similar language in its Class VI regulations.

The Commission agrees with these comments and adopts §5.203(e)(1)(B)(v) with the recommended change. The federal regulations at 40 CFR §146.86(b)(3) state that at least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.

The Texas-based organizations requested clarification on the requirement in §5.203(o) that the applicant provide a letter from the Groundwater Advisory Unit (GAU) of the Oil and Gas Division. The Texas-based organizations asked whether the GAU letter must be applicable to the entire Area of Review and whether the Commission will allow an applicant to provide a GAU letter older than five years.

The GAU letter will be applicable to the AOR and must be prepared specifically for the geologic storage facility. The Commission made no change in response to this comment.

The GLO recommended that the Commission revise the rules to require that cement plugging for abandonment be from bottomhole to surface consistent with Texas Class I practice.

The Commission declines to make this change. Neither the federal Class VI regulations nor the TCEQ Class I regulations at 30 TAC §331.46 (relating to Closure Standards) require plugging with cement from bottomhole to the surface. TCEQ regulations at 30 TAC §331.46(e) state that a well shall be plugged in a manner which will not allow the movement of fluids through the well, out of the injection zone either into or between USDWs or to the land surface. The Commission's rules in Chapter 5 require an applicant to provide a plugging plan with the application, which will be reviewed by Commission staff for adequacy. Staff will consider factors similar to those considered by the TCEQ for Class I injection wells. These factors include, but are not limited to, the type and number of plugs to be used; the placement of each plug including the elevation of the top and bottom; the type, grade, and quantity of plugging material to be used; the method of placement of the plugs; and the procedure used to plug and abandon the well.

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PBPA supports transparency but requests that the Commission clarify how it would protect proprietary or confidential information while complying with the public hearing process that serves the public interest. TXOGA and TIP also request that the Commission explain how it will handle confidential business information, such as seismic licensing and internal knowledge, in a public hearing.

The Commission refers these commenters to §1.68 of this title (relating to Confidential Materials), which addresses confidential materials filed with the Commission. Section 1.68(a) states that "[A]ll records, data, and information filed with the Commission are subject to the Texas Public Information Act, Texas Government Code, Chapter 552. If the Commission receives a third-party request for materials that have been marked confidential pursuant to subsection (b) or (c) of this section, the Commission will notify the filing party of the request in accordance with the provisions of the Texas Public Information Act so that the party can take action with the Office of the Attorney General to oppose release of the materials."

Section 1.68(b) addresses filing confidential materials in a hearing before the Hearings Division and subsection (c) addresses filing confidential materials with the Commission other than in a hearing. All applications and other required reports and information must be submitted through EPA's Geologic Sequestration Data Tool (GSDT) system; however, EPA has established provisions for maintaining confidential information associated with the Class VI program.

PBPA recommended that notice be waived in the event that a well would threaten the public or imperil USDW or in a scenario that is otherwise approved by the director.

The Commission does not agree with this comment. The notice requirements in §5.204 correspond to the federal requirements. Section 5.202(d)(2)(A)(viii) includes the list for permit modification triggers that would allow minor modifications without notice consistent with 40 CFR §144.39. The application must include an emergency response and remediation plan, which should address the operator's plans for responding to the emergencies noted by the commenter. As part of the application, notice of this plan will be provided to the public in accordance with the notice requirement. Section 5.206(h)(3) requires that, if an operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to USDWs, the operator must: immediately cease injection; take all steps reasonably necessary to identify and characterize any release; notify the director as soon as practicable but within at least 24 hours; and implement the approved emergency and remedial response plan. In addition, §5.206(c)(3) states that in the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical. No such work may commence until approved by the director. The Commission will review the proposed emergency repair in an expeditious manner.

NARO-Texas commented that the rules should ensure proper and sufficient notice of a company's sequestration activities to affected mineral and royalty owners; owners both adjacent to and within proposed storage reservoirs. NARO-Texas further commented that, for the CCUS industry to thrive in Texas, buy-in from all stakeholders is necessary. NARO-Texas recommended that the Commission revise §5.204 to add "and mineral interest owners located within," following "each leaseholder of minerals" and before "lying above or below the proposed storage reservoir" to subsection (a)(3)(A)(V) to ensure proper notice to mineral owners within the proposed storage reservoir, not just adjacent mineral owners, surface owners within the proposed storage reservoir, and leaseholders as currently required by the remaining subsections.

The Commission agrees and adopts §5.204(a)(3)(A) with a change to add "interest owner" in §5.204(a)(3)(A)(v).

The Texas-based organizations recommended that the Commission revise §5.204(a) to require issuing web-based media posts and publishing the posts on the Commission's social media including hashtags for the appropriate counties and nearby population centers. In addition, the organizations recommended that the rule require that notice be provided in Spanish without request, and instructions on how to obtain language accommodation should be provided in other languages.

The Commission agrees that the use of new forms of information technology can improve public participation and understanding of geologic storage projects and the associated injection technologies involved. The Commission will use information technologies to inform the public. This information may include schedules for hearings, briefings, and other opportunities for involvement. The Commission also encourages operators to use the internet as well as other new and established tools to explain and post information on the latest developments. The Commission will consider how to best use social media applications for important information and will encourage operators to use similar technologies to keep the public informed of geologic storage projects. The Commission made no change in response to this comment.

Texas 2036 commented that §5.204(a)(2) requires that the Commission publish notice of a draft permit for a specified time in a newspaper of general circulation in each county where the storage facility will be located. As more Texans get their news and notices from on-line, rather than print, resources, we recommend that this publication requirement be expanded to include posting on the Commission's website. Further, and in the interest of improving outreach to the Environmental Justice and Limited English Proficiency communities described elsewhere in the proposed rules, notices published on the Commission's website should be in both English and Spanish.

The Commission agrees with the recommendation to post notice of a draft permit on the Commission's website and has revised §5.204(a)(2) accordingly. The Commission will publish the notice in Spanish and English if the proposed project is located in an Environmental Justice and/or Limited-English Speaking Household community.

Texas 2036 commented that the proposed rules require that individual notice be provided to certain persons and local governmental entities in the area of a proposed CCUS project. These persons and entities qualify for notice on the basis of their surface location in relation to the underlying proposed storage site. Section 5.204(a)(3)(A)(v), (viii), (ix), and (x) use different terms to describe that site, however. These terms include "storage reservoir," "storage facility," and "facility." In the interest of ensuring a uniform and consistent application of this notice requirement, Texas 2036 recommended that the Commission replace these terms with "geologic storage facility." This term is used for other individual notice requirements within §5.204(a)(3)(A) and is defined in §5.102(28).

The Commission agrees and adopts the provisions specified in the comment with the requested changes.

The Texas-based organizations requested clarification of §5.204(a)(3) as to whether a new notice would be issued if the permit is modified based on potential new outermost boundaries of the facility.

The Commission notes the rules require a permittee to file an application to amend a permit to expand the areal extent of the storage reservoir. If the director tentatively decides to modify or revoke and reissue a permit, the director must prepare a draft permit incorporating the proposed changes. The rules further require that the director give notice of a draft permit.

The Texas-based organizations commented on §5.204(a)(5), which requires that the applicant make "diligent efforts" to identify those that will require notice. This is based on county records. The organizations recommended that the Commission also require applicants to notify city councils, county commissioners courts, and groundwater conservation districts (if applicable) in the affected counties.

Section 5.204(a)(3)(A) requires notice to the clerk of the county or counties where the proposed storage facility is located; the city clerk or other appropriate city official where the proposed storage facility is located within city limits; any other unit of local government having jurisdiction over the area where the 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 facility. The Commission made no change in response to this comment.

The Texas-based organizations recommended that the Commission revise §5.204(a)(3)(A)(viii) to read "where the proposed storage facility is or is proposed to be located for public announcement to county residents."

The Commission agrees and adopts §5.204(a)(3)(A)(viii) with the recommended change.

In addition, the Texas-based organizations recommended that the Commission revise (ix) "where the proposed storage facility is located within city limits," should read "is or is proposed to be located for public announcement to municipal or city residents."

Section 5.204(a)(3)(A)(ix) requires notification of the city clerk or other appropriate city official where the proposed storage facility is located within city limits. Section 5.204(a)(3)(A)(x) requires notification of any other unit of local government having jurisdiction over the area where the facility is or is proposed to be located. The Commission made no change in response to this comment.

The Texas-based organizations requested clarification as to whether the Commission will make a web-based form available for submitting a request to be on 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. They further commented that the Commission could make a link to the form available on its social media channels and in social media posts submitted to media outlets.

The Commission will develop a form for requesting to be on the list and include a link to the form on the Commission's webpage. The Commission made no change in response to this comment.

The Texas-based organizations requested clarification as to whether the AOR includes all parts of the outermost boundary of the proposed geologic storage facility and whether the outermost boundary of the proposed facility include all parts of the AOR.

The rule defines area of review as 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. The Commission made no change in response to this comment.

An individual commented that the amendment in §5.204(o) to add new paragraph (2)(G) to require that the permittee of a geologic storage well coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources is a very important and appropriate addition to the rule. Operators should be allowed to coordinate these operations, with the recognition that ultimate approval from the Commission will not be forthcoming if the operators fail to agree on operational procedures that will assure containment of the stored CO_2 and avoidance of endangering any USDWs.

The Commission appreciates this comment.

NARO-Texas recommended that the Commission revise §5.206 to add the following to the end of (o)(2)(G): "and take all reasonable steps necessary to minimize or correct 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 reservoir". This addition to the condition that requires coordination with an exploration and production company establishes an affirmative duty—similar to the duty to mitigate contained in subsection (E) immediately above—to lessen the impact on the production of hydrocarbons which will benefit exploration and production companies and mineral and royalty owners alike.

The Commission agrees with this comment and adopts §5.206(o)(2)(G) to include language similar to that suggested by NARO-Texas.

EDF recommended that the Commission give further thought to the issue of environmental justice (EJ). CCS will only be an effective greenhouse gas mitigation tool if it is coupled with proactive efforts to address historic disproportionate impacts on communities as well as new impacts. Moreover, it is EDF's understanding that EPA expects to begin requiring states to address this issue as a condition of receiving primacy approvals. While it is not yet clear what EPA will require, EJ is a vital issue and EDF encouraged the Commission to begin thinking outside the box as to how it can meaningfully address community impacts and engage with affected communities. EDF provided an example suggesting the Commission discuss coordination on environmental justice issues with agencies (state or federal) that have roles to play in overseeing CO_2 capture and transportation.

PBPA recommended that the Commission clarify how the Commission would establish its environmental justice efforts to best serve the communities in the Permian Basin.

The Commission agrees with EDF that it is not clear what will be required by EPA regarding environmental justice. Commission staff is following the efforts of the various federal agencies, including EPA, as they develop guidelines. Until that guidance has been finalized, the Commission finds that enhanced public outreach and public engagement will assist the Commission and the applicant to clearly describe the proposed facility, potential impacts and safeguards against those impacts, and hear and address the concerns of all communities, including environmental justice and other disadvantaged communities. The Commission acknowledges concerns that carbon dioxide capture, transportation, and geologic storage projects will add to burdens on disadvantaged communities. However, the Commission finds that CCS is beneficial to society at large for all, including disadvantaged communities.

Further, the scope of the Chapter 5 regulations is limited to Class VI injection and geologic storage of anthropogenic carbon dioxide. Potential impacts, including impacts to environmental justice communities, associated with carbon dioxide capture and transportation will be addressed during permitting associated with capture and transportation.

TXOGA and TIP also request that the Commission define “LEP,” or alternatively, that the Commission use the term “limited English-speaking household” in §5.204(a)(6) in order to align with U.S. Census Bureau terminology.

The Commission agrees with this comment and adopts §5.204(a)(6) with a change to use the term limited English-speaking household. The U.S. Census Bureau defines a “limited English-speaking household” as one in which all members 14 years and older have at least some difficulty with English. The Commission adopts §5.102 with a definition for limited English-speaking household that matches the Bureau’s definition.

Regarding §5.204(a), which requires applicants to identify whether the area of review encompasses environmental justice (EJ) or limited English-speaking household communities, TXOGA and TIP commented that the U.S. Census Bureau 2018 American Community Survey data is a recognized source that can serve to identify and consider environmental justice communities, but requested that the Commission provide additional guidelines on the criteria that may be used to identify those communities, and to direct enhanced engagement efforts in the permitting process, and to clarify the resources or tools that may be acceptable to establish that sufficient efforts were directed to engage those communities.

The Commission refers commenters to §5.204(a)(6), which requires that, if the AOR includes an EJ or limited English-speaking household community, the applicant conduct enhanced public outreach activities. Efforts must include: (1) published meeting notice in English and the identified language (e.g., Spanish); (2) comment forms posted on the applicant’s webpage and available at public meeting in

English and the alternate language; (3) interpretation services accommodated upon request; (4) English translation of any comments made during any comment period in the alternate language; and (5) to the extent possible, public meeting venues near public transportation.

To be transparent and open to input and influence, engagement processes must be understood by all stakeholders. A project proponent could begin with developing a public participation plan detailing the process that will be used to engage the public and how that process will encourage participation by diverse populations. The plan could include documentation of the public participation plan and analysis of its success and community opinion, in public reports. The plan should include procedures to provide clear, understandable information about the project, ways to work with community leaders to create common language with neutral terminology, free of jargon, and sensitive to race, ethnicity, culture, gender, disability status, and language. Documents and in-person discussions should be translated for individuals with limited English proficiency, and should provide alternative options or assistance for individuals who are physically, visually, and/or hearing-impaired. Agendas could be developed with the assistance of community representatives to better understand how the community would like information presented, questions they would like answered, and languages they speak.

Meeting times should be selected that do not conflict with work schedules and rush hours. Meeting locations should be local and accessible (e.g., reachable via public transit), of adequate size, ADA compliant, and represent neutral turf (e.g., not a government office, and not an office that requires official identification). The meetings and their proposed agendas should be advertised in a timely manner in popular print and electronic media sources, as well as radio, if appropriate. A contact with whom communities can communicate about upcoming meetings should be provided as well as a central point-of-contact to disseminate information and resolve problems. Tele- or video conferencing options could be offered to allow the public to join in-person meetings, using technology available to the public. Meetings should be designed to create an atmosphere of equal participation by avoiding a head table or panel, and providing multiple opportunities and channels for the public to voice questions and concerns. Questions and concerns should be clearly documented and information about next steps or follow-up should be communicated. Opportunities for continued participation and feedback after the project has been implemented should be created, and communication channels (e.g., via internet updates or email newsletters, by updating community leaders, etc.) established to inform the community about the status of the project.

In addition, opportunities for permitting agencies, including the Commission, should be provided to describe the permitting agency's role and contact information.

Additional guidance is available through several sources. One such source is EPA's Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide: Additional Tools for UIC Program

Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process (https://www.epa.gov/uic/quick-reference-guides-class-vi-program-implementation). Another source is EPA's EJScreen (https://www.epa.gov/ejscreen). Applicants can also review EPA's *Guidance on Considering Environmental Justice During the Development of a Regulatory Action* (https://www.epa.gov/environmentaljustice/guidance-considering-environmental-justice-during-development-action). Although this guidance document was developed to assist EPA staff in evaluating environmental justice considerations at key points in the rulemaking process, it also contains information that could be helpful to applicants. Another potentially helpful document is EPA's Technical Guidance for Assessing Environmental Justice in Regulatory Actions (https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis).

The National Petroleum Council's "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage", includes a chapter (Chapter 4) on Building Stakeholder Confidence. This chapter includes references to several successful stakeholder engagement efforts. https://dualchallenge.npc.org/files/CCUS-Chap_4-030521.pdf.

The Texas-based organizations recommended that, in order to avoid frequently updating Chapter 5 rules and to ensure the most up to date information, the Commission revise the rule language to require use of the most recent U.S. Census Bureau 2018 American Community Survey (ACS) data to identify EJ and LEP areas data available at the time of the permit application.

The Commission agrees with this comment and adopts §5.204(a)(6) with an additional change to incorporate the recommended language.

The Texas-based organizations requested clarification as to whether "efforts to include EJ and LEP communities in public involvement activities" include public hearings described in subsection (b)(2).

The Commission notes that §5.204(b)(2) requires the director to notify the applicant that the director cannot administratively approve the application 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. Upon the written request of the applicant, the director will schedule a hearing on the application. In addition, §5.204(b)(2) states that the director must hold a public hearing whenever the director finds, on the basis of requests, a significant degree of public interest in a draft permit and the director may 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. The Commission made no change in response to this comment.

The Texas-based organizations requested clarification in §5.204(b)(1)(B) of "reasonable limits" for oral statements.

The rules allow for written comments and places no limit on such comments. Oral comments may be limited in time at a hearing depending on the number of persons wishing to give such statements. The Commission made no change in response to this comment.

The Texas-based organizations recommended that the rules specify that meetings and/or hearings should be conducted in English and the identified language (e.g. Spanish). Additionally, the rule should specify that a professional interpreter must be available to provide such services. They also recommended that the Commission consider contracting with a firm that can train hearings staff and public outreach staff on procedures for conducting and coordinating multi-lingual meetings in a manner that encourages participation from LEP groups.

The Commission declines to make a change in response to the comment. The rule requires that interpretation services be provided upon request. The Commission will consider contracting with professional interpreter services as necessary.

The Texas-based organizations recommended that the Commission allow at least 60 days (rather than 30 days) for protests to be received. Non-experts who may be impacted will likely need more time to understand the process and determine whether they may be impacted. Many individuals lack the economic means to hire lawyers and may not have immediate access to educational resources needed to understand notice letters.

The Commission declines to make the requested change. The rule states that 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. The Commission may allow additional time for public comment depending on the location of the proposed geologic storage facility.

The Texas-based organizations recommend that the Commission revise the rules to include a robust environmental justice review, including evaluating the impacts of proposed Class VI wells on already overburdened environmental justice communities, not merely providing notice and language interpretation. The organizations commented that the omission of a substantive review of the environmental justice impacts of Class VI injection wells would constitute a failure of the Commission to carry out its legal obligation to ensure environmental justice through compliance with Title VI of the Civil Rights Act of 1964. Title VI prohibits the use of federal funds in a manner that is discriminatory on the basis of race, color or national origin. EPA requires state governmental entities, as recipients of federal financial assistance, to ensure environmental justice through compliance with civil rights law that prohibits discrimination. EPA's implementing regulations set forth general and specific prohibitions against discrimination that have direct application to regulatory activities under the Class VI UIC Program, such as siting.

The Commission understands that environmental justice is ensuring that all people have access to fair treatment and the opportunity for involvement in the development, implementation, and enforcement of environmental laws, regulations, and policies regardless of race, ethnicity, national origin, or income. Environmental justice is best achieved when there are equal degrees of protection from environmental and health hazards, and there is equal access to the environmental policy and decision-making process. (https://www.epa.gov/environmentaljustice).

The scope of the Chapter 5 regulations is limited to Class VI injection and geologic storage of anthropogenic carbon dioxide. Although the presence of industrial sources of carbon dioxide may factor in the selection of locations for geologic storage of carbon dioxide, the Commission has no role in permitting of many of those industrial sources (such as petrochemical plants). It is not clear what will be required by EPA regarding environmental justice. Commission staff is following the efforts of the various federal agencies, including EPA, as they develop guidelines. Until that guidance has been finalized, the Commission expects that enhanced public outreach and public engagement will assist the Commission and the applicant to clearly describe the proposed facility, potential impacts and safeguards against those impacts, and hear and address the concerns of all communities, including environmental justice and other disadvantaged communities.

§5.205

PBPA expressed concern that the annual fee, currently set at $50,000, could serve as a barrier to entry and may be more than necessary to fund the program, and incidents would likely already be covered through the financial assurance requirements.

WSP commented that the application fees are excessive, being 100 times greater than any other RRC injection permit and five to 50 times greater than the TCEQ fees imposed on similarly complex UIC permits. Having a fee structure so costly is contrary to efforts that incentivize emitters of carbon dioxide to find solutions to remove CO_2 from the atmosphere. WSP recommends establishing an application fee that is comparable with TCEQ's Class I hazardous waste injection well application fee.

TXOGA commented that §5.205(a)(3) requires applicants to pay an annual fee of $50,000 per year between the end of injection and site closure authorization. TXOGA seeks clarification on this annual fee, as it will add significant cost to a CO_2 storage project at a time when the project is not generating any revenue from the injection and permanent storage of CO_2 as a service, which could hinder deployment of this technology. It would also stray from current requirements under EPA's UIC Class VI regulation, which imposes no such fee. Further, EPA's UIC Class VI regulation requires a CO_2 storage operator to demonstrate and maintain a financial responsibility instrument sufficient to cover the cost of corrective action, injection well plugging, emergency and remedial response, and post injection site care and site closure. In §5.205(c), the Commission includes a similar requirement for financial assurance through the end of the PISC period. Therefore, CO_2 storage operators will be responsible for any incident that may occur during the post injection through site closure phase of the project and have a financial instrument, which could be surety bonds, a letter of credit, insurance, or self-insurance, sufficient to cover the cost of remediation. The annual fee can therefore be viewed as redundant, providing no clear benefit to the permanence of stored CO_2.

TXOGA and TIP have additional concerns about the Commission's proposed elimination of the anthropogenic CO_2 storage trust fund cap of $5,000,000 in §5.205(a)(4). TXOGA and TIP would like clarification on why the trust fund cap is being eliminated and requests that the Commission make clear how the trust funds will be utilized in the future. Finally, TXOGA and TIP note that while geologic CO_2 storage is not without risk, these risks are well understood, can be mitigated, and decrease over time. For well-selected, designed, and managed geological storage sites, the CO_2 will gradually be immobilized by various trapping mechanisms and retained for up to millions of years, which raises the question of what issue these fees are trying to resolve.

The Texas-based organizations commented that the Commission should consider the actual cost to the state of monitoring Class VI wells over the active life, inactive life, post-injection care period, and after the post-injection care period, and whether the proposed fees are sufficient to cover the lifetime costs of state monitoring at a level that is protective of groundwater quality, human life, and natural resources. The organizations asked how much the Commission estimates spending on inspections for Class VI facilities during the active life of each facility, inactive life, post-injection care period, and after the post-injection care period, to plug and cleanup orphaned Class VI wells and whether Commission includes other activities, such as inspections, cementing contractors, in the estimates.

The Commission responds as follows. In 2009, Senate Bill 1387 (SB 1387) established the framework for geologic storage of anthropogenic carbon dioxide. SB 1387 provided the Commission with a method for funding this new program by establishing the Anthropogenic Carbon Dioxide Storage Trust Fund through Texas Natural Resources Code §120.003 and authorizing the Commission to impose fees under Texas Water Code §27.045 to cover the cost of permitting, monitoring, and inspecting Class VI injection wells and geologic storage facilities, and enforcing and implementing Subchapter C-1, relating to geologic storage and associated injection of anthropogenic carbon dioxide, and rules adopted by the Commission under that subchapter.

The rules in Chapter 5 adopted by the Commission effective December 20, 2010, included the current language regarding fees. Section 5.205 includes three non-refundable fees: a base fee for each application to cover the Commission's costs for processing the application; an annual fee based on the number of metric tons injected into the geologic storage facility; and an annual post-injection care fee until the director has authorized storage facility closure. The Commission did not propose to change the fee amounts. Regarding the comment regarding removing the trust fund cap of $5,000,000 in §5.205(a)(4), the Commission notes that Natural Resources Code §121.003 does not place a limit on the amount in the trust fund.

States are required to apply for primacy for the Class VI UIC program under Section 1422 of the federal SDWA. Under that section, Texas must demonstrate that the State program meets EPA's minimum federal requirements. That demonstration includes adequate funding for permitting, inspection, and monitoring. The fees will assist the Commission in providing adequate resources to administer the increased complexities of the Commission's carbon dioxide geologic injection and storage program and the additional oversight requirements.

The Commission's proposed fee structure is based on the estimated cost to the Commission of reviewing applications and monitoring geologic storage facilities. The fees are not out of line with the complexity of the program and the additional staff resources that will be needed to review the complex applications and monitoring data. The Commission has been covering the cost of preparation of the rule amendments and the primacy package, as well as computer programming to add a new UIC type code and a new Drilling Permit purpose of filing code to both the mainframe and open system applications.

The Commission notes that in 2008 the EPA estimated the cost of performing the necessary work for and preparing the application at approximately $1,481,775 per application. EPA also estimated that the recurring costs for a facility that has been permitted and is operating will be $1,705,294 a year; and the cost of post-injection monitoring and reporting at $216,092 a year. *See* "Information Collection Request for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells--Proposed Rule," OMB Control No. 2040-NEW, EPA ICR No. 2309.01, July 2008. The fees included in the Commission's rules are reasonable compared to these other costs. The Commission made no change in response to these comments.

The Texas-based organizations commented on §5.205(c)(2)(C), which requires the director to approve the amount of financial assurance for a geologic storage facility, but specifically excludes plugging costs from being included in the estimate of costs of closure. The Texas-based organizations commented that subsection (c)(1) states that the operator must comply with the requirements of §3.78 of this title (relating to Fees and Financial Security Requirements) for all monitoring wells and injection wells. Section 3.78(g) only requires financial security in the amount of $2.00 per foot of well depth for individual wells, but allows blanket bonding that comes out to amounts of bonding at potentially $2,500 or less per well. The Commission spent an average of $8.48 per foot to plug wells across the state from

FY 2015 – FY 2020. The Texas-based organizations also expressed concern that the financial security requirements in §3.78 are so low that thousands of orphaned wells and sites have been on the Commission's orphaned wells list for decades. The Texas-based organizations further expressed concern that operators would have the ability to request indefinite plugging extensions on inactive wells.

Because the Commission must ensure that there are no potential conduits for the escape of stored carbon dioxide, the Commission plans to require that all wells associated with a Class VI project are properly plugged before issuing a closure certificate. However, a close review of the federal regulations indicates that the closure costs must include the cost of plugging the wells. Therefore, the Commission has revised the language to require that the estimated closure cost and financial assurance include the cost of well plugging.

The Texas-based organizations commented that §5.205(c)(2)(C)(i) indicates that a qualified professional engineer does not need to prepare a written estimate of the "highest likely dollar amount necessary to perform post-injection monitoring and closure of the facility," but instead that the engineer may supervise preparation of the estimate. The organizations recommend that the estimate should be directly prepared by a qualified professional engineer, and not merely supervised.

The Commission declines to make the requested change. Section 5.205(c)(2)(C)(i) requires that a qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, 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. The Texas Engineering Practice Act requires that the professional engineer seal the estimate.

The Texas-based organizations noted that the director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors and requested clarification as to the factors and corrective action.

The Commission notes the federal and state regulations allow operators to defer some identified corrective action needed within the AOR, but farther away from the injection well, until after injection has commenced, but prior to carbon dioxide plume and pressure front movement into that particular area. Such corrective action may include plugging of wells in the AOR. The Commission will consider factors specific to the particular geologic storage site. The Commission made no change in response to this comment.

The Texas-based organizations commented that 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. The organizations recommended that the Commission not approve a reduction in the amount of financial assurance required to avoid liability to the Commission for post-injection monitoring after the monitoring period is over.

The Commission declines to make the recommended change. In the PISC and Site Closure Plan, an operator may propose reducing the frequency of monitoring during the post-injection phase if it can be demonstrated based on monitoring results that the potential for endangerment of USDWs has decreased over time. Specific, risk-based, quantitative criteria that will indicate that a reduced monitoring frequency is appropriate may include the reservoir pressure reaching a certain level relative to pre-injection conditions or steady or favorable trends in observed geochemical monitoring results over a pre-defined period. A prediction of the timeframe for pressure decline, based on the current and calibrated AOR delineation modeling, upon the cessation of injection must be included with the alternative PISC demonstration as required by 40 CFR §146.93(c)(1)(ii). The demonstration of pressure decline should include the full spatial extent of pressure front evolution at the project site.

A prediction of the rate of carbon dioxide plume migration, and the timeframe for the cessation of migration must be included in the demonstration for an alternative PISC timeframe. This assessment should include the full spatial extent of plume evolution at the project site, including both the lateral and vertical extent. The operator should use plots and cross sections of plume extent at various time intervals during post-injection monitoring until its mobility ceases or it reaches a potential receptor. When the plume is migrating at a rate such that this timeframe becomes exceedingly long (e.g., thousands of years), the plume migration rate may be considered sufficiently minor as to not pose an endangerment to USDWs. The plume migration assessment can also be supported by saturation profiles at specific locations, such as monitoring wells. Site-specific plume monitoring results may also be used to support these predicted assessments.

The operator must also identify specific processes leading to carbon dioxide trapping and trapping rates, including physical entrapment and immobilization at the injection zone/confining zone interface, and capillary trapping.

The Texas-based organizations commented that §5.205(d)(1) requires notice of adverse financial conditions be submitted by certified mail and recommended that the Commission allow notice also to be submitted by electronic mail.

The Commission disagrees. Section 146.85(d) of the federal Class VI regulations requires that the operator give notice of adverse financial conditions by certified mail.

The Texas-based organizations recommended that §5.205(d)(3) be revised to reduce the amount of time to replace the bond from 90 days to 30 days.

The Commission agrees the time period should be decreased. Title 40 CFR §146.85(d)(3) requires the operator to establish other financial assurance within 60 days. Therefore, the Commission adopts §5.205(d)(3) with a change to incorporate a 60-day timeline.

The Texas-based organizations commented on §5.205(n)(2), which requires the director to rely on the applicant's most recent audited annual report and quarterly report filed with the U.S. Securities and Exchange Commission or the person's most recent audited financial statement and "the date of the audit must be not more than one year before the date of submission of the application." The organizations requested clarification as to whether the director will have the authority to request updated an audit report if the application approval process takes longer than one year.

Section 5.205(c)(2)(E) requires the operator of a geologic storage facility to provide to the director 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 operator must provide to the director upon request an adjustment of the cost estimate if the director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging and post-injection storage facility care and closure. The Commission made no change in response to this comment.

The Texas-based organizations requested clarification as to the source of funding to allow the Commission to pay for future well plugging and cleanup of orphaned Class VI wells that exhibit casing failures after 20 years. The organizations also requested clarification regarding the speed with which the Commission will conduct plugging and cleanup of orphaned Class VI wells.

The Commission cannot issue a closure certification for a facility until all wells have been properly plugged. Until a certification has been issued, the permittee must maintain financial assurance for the geologic storage facility and pay the annual fee in §5.205. In addition, Texas Natural Resources Code §121.003 establishes the Anthropogenic Carbon Dioxide Storage Trust Fund and Texas Water Code §27.045 authorizes the Commission to impose fees to cover the cost of permitting, monitoring, and inspecting Class VI injection wells and geologic storage facilities, and enforcing and implementing Subchapter C-1, relating to Geologic storage and associated injection of anthropogenic carbon dioxide, and rules adopted by the Commission under that subchapter. The trust fund consists of fees imposed under §5.205, penalties imposed for violations of Subchapter C-1 or rules adopted under that subchapter, funds received by the Commission from financial responsibility mechanisms; and penalties imposed for violations of Commission rules adopted under §382.502, Health and Safety Code.

Section 121.003 of the Texas Natural Resources Code authorizes the Commission to use the trust fund for permitting, inspecting, monitoring, investigating, recording, and reporting on geologic storage facilities and associated anthropogenic carbon dioxide injection wells; long-term monitoring of geologic storage facilities and associated anthropogenic carbon dioxide injection wells; remediation of mechanical problems associated with geologic storage facilities and associated anthropogenic carbon dioxide injection wells; repairing mechanical leaks at geologic storage facilities; plugging abandoned anthropogenic carbon dioxide injection wells used for geologic storage; training and technology transfer related to anthropogenic carbon dioxide injection and geologic storage; and compliance and enforcement activities related to geologic storage and associated anthropogenic carbon dioxide injection wells.

The Commission made no change in response to this comment.

§5.206

Denbury recommended that the Commission clarify the word "injure" found in §5.206(b)(1). Denbury recommended that "injure" be more clearly defined to reduce the scope of potential interpretations.

The EAC commented that the amendments properly focus on protecting existing or prospective subterranean resources or wasting of such resources due to the injection of carbon dioxide; however, it urged the Commission to reflect on the excessive breadth of the term "injure" used in the proposed language. EAC commented that the language warrants greater precision of definition and reduction in the potential scope of its interpretation to obviate future disputes concerning the intent of the provision on protecting other resources.

The Commission disagrees with these comments. The language in §5.206(b)(1) is consistent with the language in §27.051(b-1)(1) of the Texas Water Code, which states that the Commission may issue a permit if it finds that "the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation." The statutes do not define the term "injure." However, the Commission notes that the same "endanger or injure" language appears in Texas Water Code §27.051(b)(1), regarding other types of injection wells under the jurisdiction of the Commission. Therefore, the phrase "endanger or injure" with respect to Chapter 5 has the same scope as the Commission has historically used for issuing injection well permits. The Commission made no change in response to this comment.

The Texas-based organizations and individuals commented on §5.206(b)(9) regarding the applicant's 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. The Texas-based organizations ask why the Commission only requires a good faith claim to operate in the first five years after initiation of injection when the facility's storage is required to be permanent.

The Commission notes that §5.207(a)(2)(D)(iv) requires that the operator submit an annual report detailing 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. The Commission made no change in response to this comment.

TXOGA and TIP expressed concern with the modification of the notice requirement in §5.206(c) to require notice to the Commission 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." The rules currently require no more than 48 hours' notice. This change will cause significant difficulty, as operators are often not aware of the need for such work 30 days in advance of commencing workover or remedial operations. TXOGA and TIP recommend that the Commission consider including language allowing notice to be waived when the well endangers the public or USDW, such as when casing or cement failures may contaminate USDW, or when otherwise approved by director.

The EAC agrees that providing the Commission with sufficient notice to witness planned well workovers and other stimulation activities is appropriate. However, EAC views the amount of time for such notice reflected in the proposal to be excessive, raising the risk that unnecessary downtime and operating delays will result. Noting that previous notice requirement was 48 hours, the EAC recommends that the 30-day notice period be reduced to seven days rather than the 30 days proposed.

The Commission declines to change the proposed language. Section 5.206(c)(3) states that, 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. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical. No such work may commence until approved by the director. The operator must notify the Commission as soon as possible in the case of an emergency and obtain approval from the director.

WSP and an individual commented that the proposed wording in §5.206(c)(3) creates confusion about whether the prohibition on commencing work also applies to "emergency repairs", which does not appear to be the intent. The individual recommended that the Commission relocate the final sentence to follow the sentence that excludes emergency repairs as follows.

The Commission agrees with these comments and adopts §5.206(c)(3) with a change to relocate the last sentence as suggested.

The Texas-based organizations recommended that the Commission revise §5.206(e) to detail the type and frequency of monitoring considered to be "sufficient" (e.g., monthly, quarterly, or annually).

The frequency of testing and monitoring will depend on the rule requirements and on site-specific conditions. The Commission will use the EPA's Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance (EPA 815-R-13-001, March, 2013) as guidance. For example, the guidance document states that project-specific frequency may be determined (e.g., based on variability in ground water chemistry) and approved by the UIC Program Director. Sampling frequency may be reduced based on project-specific benchmarks, such as generally stable conditions observed in several successive sampling rounds. Likewise, sample frequency may need to be increased if the results of monitoring indicate possible fluid leakage or endangerment of USDWs at a particular location. Certain constituents may be monitored near-continuously using dedicated downhole sensors, such as pH and specific conductivity. The Commission made no change in response to this comment.

TXOGA and TIP commented that there is an inconsistency between §5.206(d)(2)(C) and §5.203(f)(2)(C). Section 5.206(d)(2)(C) limits the injection pressure to 90% of the fracture pressure of the injection zone, whereas §5.203(f)(2)(C) is not clear on whether the 90% limit of the fracture pressure applies to the injection zone or the confining zone. TXOGA and TIP recommended that the limit of the fracture pressure be applied only to the confining zone, which is consistent with EPA's implementation manual. Accordingly, TXOGA and TIP recommended that the Commission revise §§5.206(d)(2)(C) and 5.203(f)(2)(C) to resolve the inconsistency and to clarify that the 90% limit should be applied only to the confining zone.

The Commission agrees that clarification is needed but declines to make the requested change. The federal regulations at 40 CFR §146.88(a) state that "Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection 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. Pursuant to requirements at 40 CFR §146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit."

In addition, EPA's UIC Program Class VI Implementation Manual for UIC Program Directors recommends that program directors "Review the proposed maximum injection pressure to confirm that it is no more than 90 percent of the fracture pressure of the injection zone. . . .If the proposed maximum fracture pressure is greater than 90 percent of the fracture pressure of the injection zone, require a change in the injection pressure to ensure compliance with 40 CFR 146.88(a)."

Therefore, except during approved stimulation activities, injection pressure may not be greater than 90% of the fracture pressure of the injection zone. The Commission adopts §5.203(f)(2)(C) with a change to clarify these requirements.

The GLO recommended that the Commission revise the rules to prohibit initiation or propagation of fractures in the injection zones through stimulation, consistent with the Texas Class I regulations. The GLO commented that the rules allow approved stimulation of the injection zone, which could impact the storage seal and lead to a reduction of the maximum allowable storage pressure, and, consequently reduce storage capacity and the associated revenue available to the PSF as the facility owner. Fractures, once created, require relatively less stress to propagate – all other things equal. The GLO particularly expressed concern with fracturing Miocene age sediments comprising the best offshore Texas storage reservoirs because of the region’s highly faulted and compartmentalization.

The Commission understands this concern but makes no change in response. If well stimulation is proposed, the Commission will review the proposed procedures to ensure that well integrity will be maintained and that the confining zone will not be fractured. The Commission will compare proposed stimulation pressures to well material strength and formation fracture pressures and compare the composition of any stimulation chemicals proposed to the chemical resistance of the well materials. If it appears that any proposed stimulation procedures might harm the well or fracture the confining layer, the Commission will require that the stimulation plan be revised or will not allow stimulation. If it is not clear whether stimulation procedures might damage the well or confining layer, the Commission will consider requesting modeling of the stimulation activity and resultant fracture patterns or increased monitoring of pressure and other variables with appropriate safeguards during stimulation. If approved well stimulation is performed, the Commission will review post-stimulation documentation.

The GLO also recommended that fracture stress be calculated using rock data from cores that comprise all the relevant lithologies in the injection and confining zones when considering maximum allowable surface injection pressure. Fracture stress will be the minimum strength among these lithologies—not an average value, as the rock will fracture as its weakest point first. The GLO believes safety factors should then be applied to the minimum value of fracture stress.

The Commission will evaluate geomechanical and petrophysical information to verify that the applicant has submitted sufficient information to characterize all required parameters throughout the project area. This includes porosity, permeability, capillary pressure, and information on fractures, stress, ductility, rock strength, and in situ fluid pressures. The Commission will verify that the applicant provides information on and the variability in measurements for the various types of geomechanical and petrophysical data. The Commission will review information on the mineralogy, petrology, and lithologies of the injection and confining zones and verify that the cores on which this information is based were collected from representative locations and that they include the injection and confining zones—or that cores will be taken as part of the pre-operational formation testing program. If there is evidence of heterogeneity, the Commission may request that additional cores be taken and analyzed to characterize the site geology as thoroughly as possible. The Commission will verify that measurements of ductility and rock strength are based on appropriate laboratory tests that are suitable for simulating downhole stress conditions. In addition, the Commission will verify that information on in situ stress incorporates measurements of vertical stress, maximum horizontal stress, and minimum horizontal stress and that the applicant used appropriate methods to measure stresses. The Commission made no change in response to this comment.

Regarding §5.206(d)(2)(D), which requires that the operator maintain on the annulus a pressure that exceeds the operating injection pressure, TXOGA and TIP support adding pressure to the annulus to improve monitoring efforts but cautions that this pressure should not exceed the safe working pressure for the well. Specifically, anything greater than the equivalent bottom hole injection pressure would be excessive. The EAC observed that due to the gradient differential between water and CO_2 there exists the prospect that a higher annulus pressure at the well surface can produce a very significant pressure differential "downhole" in the well. Denbury and the EAC recommended that that the Commission change the clause "maintain on the annulus a pressure that exceeds the operating injection pressure" to "maintain on the annulus a bottom hole pressure that exceeds the operating injection pressure."

The Commission notes that the federal rule in 40 CFR §146.88(c) requires that the operator fill the annulus with an approved non-corrosive fluid and maintain pressure on the annulus that exceeds the operating injection pressure. Maintaining an annulus pressure that is higher than the injection pressure, will ensure that if there are leaks in the tubing, the annulus fluid will move into the tubing, rather than the injectate moving out of the tubing and potentially along the outside of the well. This requirement is appropriate for Class VI wells given the potential high volumes and supercritical nature of the CO_2 injectate, potential geomechanical stresses in the wellbore, and the potential for movement of the CO_2 in the event of a mechanical integrity loss.

The Commission agrees that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the rules provide the director with discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. Section 5.206(d)(2(D) states that: "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*" (emphasis added). The Commission made no change in response to this comment.

The Texas-based organizations recommended that the Commission revise §5.206(h)(2)(C) to require the information to be submitted with every annual report.

The Commission agrees and adopts §5.206(h)(2)(C) with the requested change.

WSP commented that §5.206(h)(4)(i) references notifying the Commission prior to performing work on an injection well; however, there is a discrepancy in the language regarding the form of notification and when work shall commence. WSP recommended revising the language to require that a proposed schedule of activities be submitted in writing to the Commission.

The Commission does not agree with the recommended revision of §5.206(h)(4)(i) because the language as proposed is consistent with the federal regulations. The Commission made no change in response to this comment.

Regarding §5.206(i), Denbury recommended that the requirement of a 30-day notice to the Commission prior to any planned testing or logging be reduced to a 7-day notice. The rules currently require no more than 48 hours' notice. Seven days would allow scheduling flexibility and limit downtime while still providing RRC with an opportunity to witness the activity.

The Commission declines to change the proposed language. Title 40 CFR §146.87(f) of the federal rules requires the operator to submit a schedule of all logging and testing to the director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

The GLO commented that injection of CO_2 should be required to be under supercritical conditions, because injection of liquid CO_2 in the reservoir could create undesirable thermal stresses and either initiate or propagate fractures in the injection zone.

The Commission disagrees. The federal and state regulations do not require that carbon dioxide be injected in the supercritical state. An applicant would be required to consider the phase and characteristics of carbon dioxide to be injected. To transport captured CO_2 for geologic storage, operators typically compress carbon dioxide to convert it from a gaseous state to a supercritical state (IEA, 2008). The Commission believes that many operators will inject CO_2 in a supercritical state to depths greater than 800 meters (2,645 feet) to maximize storage capacity.

The Texas-based organizations requested clarification as to whether the requirement in §5.206(k)(6)(A) for a survey plat submitted with the storage facility closure report that indicates the location of the injection well relative to permanently surveyed benchmarks include latitude and longitudes coordinates of the well. The Texas-based organizations recommended that the Commission include language in subsection (b) that specifies the geographic coordinate system the map should use. The organizations also recommended that the rule language specify how accurate the location data should be, within a specified margin of error for coordinates depicted compared to actual (e.g. number of feet).

The Commission agrees and adopts subsection (k)(6)(A) with a change to address this concern.

The Texas-based organizations commented that §5.206(o)(2)(C) should be revised to include mitigation resulting from actions that are considered to be compliant.

The Commission declines to make the requested change. The language in §5.206(o)(2)(C) is standard language required by the federal regulations. The rules include requirements and procedures for correcting adverse impacts on the environment that are discovered even if the operator is in compliance with the permit and regulations.

The Texas-based organizations also commented on §5.206(o)(2)(G). The Texas-based organizations expressed concern that drilling through the AOR would be allowed. They also requested that the Commission clarify the term "coordinate" and requested that the Commission explain the level of scrutiny with which the Commission will examine drilling permits for wells that are within the AOR and clarify whether the public will receive notice and have an opportunity to comment.

The Commission does not have the authority to prohibit the drilling of wells for the exploration of oil or gas or geothermal resources through the AOR. However, the Commission does have the authority to require both the operator drilling the oil or gas well and the operator of the geologic storage facility to coordinate in a manner consistent with the Commission's authority in Texas Natural Resources Code Chapters 85 and 91, as well as Water Code Chapter 27. Texas Natural Resource Code §91.015 states that "Operators and drillers that drill for oil or gas shall use every possible precaution in accordance with the most approved methods to stop and prevent waste of oil, gas, or both oil and gas in drilling operations and shall not wastefully use oil or gas or allow oil or gas to leak or escape from natural reservoirs." Texas Water Code §27.051 authorizes the Commission to issue a permit for the geologic storage of carbon dioxide if it finds, among other things, that the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation, that, with proper safeguards, both ground and surface fresh water can be adequately protected from carbon dioxide migration or displaced formation fluids, and that the injection of anthropogenic carbon dioxide will not endanger or injure human health and safety.

As stated in the proposal preamble, the Commission plans to designate the AOR of geologic storage projects on the GIS maps used by the Drilling Permits Section to alert the section of a drilling permit application for a well within the AOR. A condition will be included in the drilling permit requiring the drilling permittee to notify and coordinate with the permittee of the geologic storage project of its plans to drill. The Commission made no change in response to this comment.

5.207

The Texas-based organizations recommended that the Commission revise §5.207(a)(1) to require operators to apply “best practices” not only “generally accepted” methods and standards for test evaluation.

The Commission declines to make the requested change. The language is consistent with the language in 40 CFR §146.89(f).

Texas 2036 commented that §5.207(a)(2)(D) requires that an operator submit an annual report to the Commission detailing the tons of CO_2 injected, among other items. Texas 2036 recommended that the Commission amend this section to include the source(s) of the injected CO_2. In addition, the annual report should disclose if the current sources of CO_2 have changed from those sources described in the permit application’s fact sheet. These data will be important to the Commission’s monitoring and tracking of its CCUS permitting program. Moreover, these data will provide the public with a clear understanding of the types of industries engaging in CCUS programs. This level of reporting and transparency would work to enhance the policy argument for continued and expanded CCUS in Texas.

The Commission notes that §5.203(i)(1)(C) and (D) require the applicant to submit an operating plan that includes the sources of the CO_2 stream and the volume of CO_2 from each source; and an analysis of the chemical and physical characteristics of the CO_2 stream prior to injection. Section 5.206(d)(1) requires that the operator maintain and comply with the approved operating plan. Section 5.207(a)(2)(C)(ii) requires the operator to submit a semi-annual report that includes changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data. Section 5.207(a)(2)(D) requires the operator to submit an annual report that includes a statement confirming that the operator has reviewed the operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 and determined whether any updates were warranted by material change in the operational data or in the evaluation of the operational data by the operator. 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. 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. However, the Commission agrees that clarification would be helpful and has revised §5.207(a)(2) to require reports if there are changes to the source of the CO_2 stream.

The GLO has jurisdiction over the leasing of most State-owned uplands and submerged lands for the purpose of energy resource development, including, but not limited to, offshore carbon sequestration activities under Texas Clean Air Act H&SC §382.501. Revenue from energy leases accrues to the Texas Permanent School Fund (PSF). The maximum bond guarantee amount allowed under current federal law is $117 billion, which makes aggressive growth of the PSF vital to the long-term financing of Texas public education. The GLO has a fiduciary duty to protect the physical and financial integrity of its assets- including offshore carbon storage reservoirs. The GLO recommended that every reference to "volume" in the proposed rules be changed to "mass" and that all continuous monitoring and measurement plans and requirements should include either both volume and density or else a direct mass measurement. GLO further commented that the rules should also require that temperature be measured and monitored in all instances where pressure measurement and monitoring is required. The GLO commented that CO_2 is a compressible fluid and must be measured and monitored accordingly. Although the measurement in terms of volume is common practice in the natural gas industry, the highly compressible behavior of caron dioxide near the critical point makes it even more important to measure mass, rather than volume. Moreover, all custody transfer measurements of CO_2 for tax credit or offset credit computation purposes are made in terms of mass –specifically metric tons (1 metric ton = 1000 kg).

The GLO noted that errors in measurement due to volume discrepancies at different temperatures and pressures measured at different locations can result in large mass balance calculations, particularly as the density of carbon dioxide can change as much as 70% over a temperature change of less than 5° C near critical pressure. Thermodynamic equations of state exist for conversion of volume, temperature, and pressure measurements to mass; however, the need to control and measure each of those quantities independently creates additional uncertainty in the derived mass quantity. Fiscal carbon measurements will be more accurate if all the allowable uncertainty is either applied to a single mass measurement or aggregated from combined measurements of density and volume; otherwise, density changes could result in payment errors.

The GLO's comment pointed to a review of flowmeters for use in the CCS projects conducted by researchers at Heriot Watt University. The review emphasizes the need for accurate mass measurement in carbon custody transfer or other fiscal applications as follows: "Examples exist for large scale CCS projects. For example, the Sleipner project uses ultrasonic meters, while both the In Salah project ad Vattenfall projects employ orifice plates. The Yates project uses orifice plates supplemented by Coriolis meters and Sheep Mountain project operates both turbine meters and densitometers. It may appear that the task of choosing mass flowmeters suitable for CCS has already been accomplished; however, there is one major difference between the projects listed above and those of the future: the matter of accuracy. In these earlier projects the operators were not compelled to record the mass flowrate of CO_2 within the bounds determined by EU ETS."

The GLO further commented that the Texas Clean Air Act requires the GLO to publish annual reports on the "total volume of carbon dioxide stored", "the total volume of carbon dioxide received for storage during the year", and "the volume of carbon dioxide received from each producer of carbon dioxide. The determination of "stored" volumes demands an analysis of the various physical carbon dioxide trapping mechanisms (structural, capillary, dissolution and mineralization) that is conducted through the interrogation of models and data submitted by the Class VI permittees. Reconciliation of the mass balance among the received, injected, and stored CO_2 quantities affects the periodic auditing of rental payments made to the State and the verification of tax credits. Inconsistencies among the quantities will need to be reconciled.

The Texas-based organizations also requested the measurement of CO_2 by mass in addition to volume.

The Commission agrees with this comment and adopts the following provisions with changes to address these comments: §5.203(d)(1)(A), §5.203(e)(2)(D), §5.203(h)(1)(C), §5.203(i)(1), §5.203(j)(2), §5.206(d)(2), §5.206(k)(6)(C), §5.206(l)(5), and §5.207(a)(2)(C). Operators of geologic storage facilities will be collecting data on the mass of carbon dioxide injected under Section 45Q of the federal Internal Revenue Code.

The GLO expressed support for the Commission's decision to rely on the EPA's GSDT for submission and retention of all permitting data and documentation. However, the GLO recommended that all interested parties have access to the electronic archive and that all notices, draft permits, monitoring reports and permit correspondence be included in the archive.

The Commission will archive information regarding notices, draft permits, monitoring reports, and permit correspondence. Some of this information will be available electronically. The Commission made no change in response to this comment.

The Texas-based organizations commented on §5.207(e), which requires operators to retain all wellhead pressure records, metering records, and integrity test results for at least 10 years. The Texas-based organizations recommended that the Commission require records to be retained for the entire life of the well and the post-injection site care period.

Similarly, the Texas-based organizations recommended the Commission revise §5.206(m) to require record retention for the entire life of the facility including the PISC period and to require consideration of the costs of maintaining these records in perpetuity in the financial security requirements.

The GLO recommended that the Commission modify the requirement to retain "records, including modeling inputs and data to support area of review calculations and integrity test results, for at least 10 years" to mandate permanent archive in the EPA Geologic Data Storage Tool with access granted to the public for purposes of independent computational modeling and validation in support of safety and royalty payment auditing.

The Commission will archive information regarding notices, draft permits, monitoring reports, and permit correspondence. Some of this information will be available electronically. The Commission made no change in response to this comment.

The GLO commented that compliance with applicable international standards should be mandatory. The proposed rules state that "the director must apply methods and standards generally accepted in the industry." This should be revised to also mandate compliance with international standards applicable to geologic carbon sequestration, particularly ISO Standard 27914 "Carbon dioxide capture, transportation and geologic storage – Geological storage." This standard was authored in part by researchers at the Bureau of Economic Geology (BEG) at the University of Texas at Austin and will serve as a consistent and uniform set of requirements for monitoring, reporting, and verification (MRV). Not only will adoption of this standard ease the Commission's regulatory burden by streamlining the requirements for MRV, but it will eliminate discordance among MRV plans among operators which could complicate leasing, measurement, or auditing of carbon storage.

The Commission notes that the ISO Standard 27914 is a "standard generally accepted in the industry" and declines to make a change in response to the comment.

Texas 2036 commented that CCUS will be an integral component to Texas' continued energy expansion. If the EPA approves the agency's request for enforcement primacy of the Class VI underground injection well program, then the Commission's new jurisdiction will play a critical role in statewide CCUS deployment. In light of the critical nature of this program, and its important work to remove anthropogenic carbon dioxide from Texas' air, Texas 2036 recommended that the Commission develop public-facing metrics to inform Texans of the permitting program's success. Examples include: the number of CCUS facilities permitted; tons of CO_2 sequestered per year; and volumes of sequestered CO_2 emissions by source type. The Commission has already developed exceptionally informative data visualization maps highlighting state oil and gas production and permitting. Texas 2036 encouraged the Commission to consider developing similar maps for CCUS data once it becomes available.

The Commission will develop information regarding geologic storage of carbon dioxide for public consumption. The Commission made no changes in response to this comment.

Other Topics of Concern

Earthquakes

The Texas-based organizations expressed concern with blowouts and induced seismicity events across Texas that are likely related to Class II injection. EDF believes it is important for Texas to adopt measures that make sure CO_2 injection projects do not cause earthquakes that would alarm the public and risk causing damage to life and property, even though doing so is not strictly necessary in order to obtain primacy. The commenters note the seismicity provisions of EPA's Class VI rule are limited to preventing earthquakes that are so large that they would jeopardize containment and thereby jeopardize USDWs.

Smaller earthquakes can alarm the public and do damage even if they don't threaten containment. The Commission, fortunately, has broad powers to guard the public welfare and is not limited the way EPA is.

The GLO commented that consolidation of injection-induced fractures near lateral fault boundaries may – under the right combination of initial fracture trajectory and geomechanical stress state – create conditions that may result in lower fault surface cohesion. Lower fault surface cohesion could lead to fault slippage, higher fault transmissivity and new carbon leakage pathways, or more favorable conditions for induced seismicity. Numerical modeling studies of geologic carbon injection have also shown that there is the potential for injection zone fractures to intersect the confining zone and create localized higher permeability channels through which CO_2 could migrate.

EDF recommended that the Commission add provisions to require permittees to appropriately monitor for induced seismicity and to perform a risk analysis based on the resulting data that would indicate whether there is a significantly increased risk of felt earthquakes. If there is a significantly elevated risk, mitigation should be required. With some adjustments, EDF believes that section 4.3.2.3 (Seismicity Monitoring) of the CCS protocol adopted by the California Air Resources Board for projects seeking to qualify for the state's large Low Carbon Fuel Standard credit could serve as a useful model. In the alternative, EDF recommended that the Commission include conditions in individual permits to achieve this same end. If the Commission prefers that approach, it might still be a good idea to add language to the proposed rule to serve as a basis for the permit conditions.

The Commission is aware that seismicity induced by fluid injection is a widely observed phenomenon and that the rates and maximum magnitudes of induced earthquakes generally increase with rising reservoir pressures, total fluid volumes and injection rates. However, mitigation and monitoring measures can reduce risk.

Section 5.203(c)(2)(D) requires an applicant to submit information on the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment. This information should include a summary of the applicant's evaluation of seismic risk, including the site-specific information reviewed. If there is uncertainty about the geologic characterization of the site or concerns about induced seismicity, the Commission may require additional information, which may include seismic monitoring at the site. If site characterization and modeling suggest that induced seismicity is a concern, the applicant will be required to address it in the Emergency and Remedial Response Plan. The Commission may also consider including permit conditions designed to minimize risks associated with potential seismic events, such as seismic monitoring. However, the Commission agrees that the rules are not clear that such measures and actions may be required and adopts §5.203(l) and §5.206(e) with changes to address this concern.

Well Plugging and Financial Assurance

The Texas-based organizations commented that the Commission appears to be holding Class VI wells to the same plugging and financial assurance standards that oil, gas, and injection wells are held to in Texas. These standards have allowed the state to accumulate approximately 140,000 inactive unplugged wells and nearly 8,000 orphaned wells. The Commission does not collect sufficient amounts of financial assurance to be able to plug all of the orphaned wells the agency takes on in a reasonable timeframe, and these delays have resulted in leaks and blowouts. Holding Class VI wells to the same standards will be unacceptable and will eventually result in hazardous leaks that can cause fatal asphyxiation or brain damage. The rule needs to address hazards posed by CO_2 leakage, considering severe impacts after a pipeline rupture in Satartia, Mississippi.

The Commission declines to make any changes. The goal of financial responsibility is to ensure that financial resources are available to prevent endangerment of USDWs from improper plugging, remediation, and management of wells in the event that the operator experiences financial difficulties. As such, operators must demonstrate financial responsibility for, among other things, any needed emergency and remedial response actions that are necessary to mitigate endangerment or potential endangerment of USDWs.

The Texas-based organizations requested clarification of operator liability upon transfer of facilities, whether asset retirement obligations can be transferred in whole or in part, and whether the Commission will be reviewing whether facility transfers are being made to financially solvent operators.

The Commission notes §5.202(c) requires an operator to notify the Commission of an intended permit transfer and provide information enumerated in subsection (c)(1)(A). Subsection (c)(2) requires that the operator acquiring the permit provide the director with evidence of financial responsibility satisfactory to the director in accordance with §5.205. An operator remains responsible for the geologic storage facility until the director approves in writing the sale, assignment, transfer, lease, conveyance, exchange, or other disposition and the person acquiring the storage facility complies with all applicable requirements. Section 5.205(c)(1)(B) prohibits the Commission from approving the transfer of the facility permit until the new operator provides the financial assurance required by this subchapter. A new operator shall not assume operation of the geologic storage facility without a valid permit. The Commission made no change in response to this comment.

The Texas-based organizations expressed concern with the incentive that would lower financial assurance based on post-injection monitoring and/or corrective action. An incentive that lowers financial assurance requirements is misguided and prematurely shifts the cost burden of state monitoring to the public. Costs of facility care and monitoring will likely increase over the life of the well, not decrease - even after the post-injection care period.

The Commission notes §5.205(c) states that the director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors and that 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.

While geologic CO_2 storage is not without risk, these risks are well understood, can be mitigated, and decrease over time. For well-selected, designed, and managed geological storage sites, the CO_2 will gradually be immobilized by various trapping mechanisms and retained for decades. For a well-sited, characterized, operated and managed site, the risks accumulate during the operational phase, but decline as injection ceases and the site moves from post-injection site care to closure to eventual long-term care. The International Energy Agency (IEA) has stated that carbon dioxide can be stored in deep geological formations in a process that mimics how oil and gas have been trapped underground for millions of years. Captured carbon dioxide is compressed and injected into a reservoir of porous rock located under an impermeable layer of rock (the cap rock). The carbon dioxide is prevented from migrating to the surface by the cap rock as well as other trapping mechanisms related to how the carbon dioxide behaves in the subsurface (https://www.iea.org/commentaries/the-world-has-vast-capacity-to-store-co2-net-zero-means-we-ll-need-it).

There are several trapping mechanisms. Once carbon dioxide is injected into a reservoir, it slowly moves upward through the reservoir until it meets this layer of impermeable rock, which acts like a lid the carbon dioxide cannot pass through. This is what's referred to as "structural storage" and is the same mechanism that has kept oil and gas locked underground for millions of years. Over time, the carbon dioxide trapped in reservoirs will often begin to chemically react with the minerals of the surrounding rock, essentially locking the carbon dioxide into the rock in a process called "mineral storage." In the case of saline aquifers, as well as structural and mineral storage, the carbon dioxide can dissolve into the salty water in a process called "dissolution storage." In any given reservoir, each (or all) of these processes work to store carbon dioxide indefinitely.

While there remains some possibility of carbon dioxide leakage from a site, research suggests it will be minimal. One study, published in the journal Nature, suggests more than 98% of injected carbon dioxide will remain stored for over 10,000 years (Estimating geological CO_2 storage security to deliver on climate mitigation, Nature Communications, June 12, 2018, Alcalde, et al., https://www.nature.com/articles/s41467-018-04423-1). Another study of natural-occurring 100,000 year-old carbon dioxide reservoirs showed no significant corroding of cap rock, suggesting the greenhouse gas has not leaked back out. The carbon dioxide must remain buried for at least 10,000 years to avoid the impacts on climate. By studying a natural reservoir in Utah, USA, where carbon dioxide released from deeper formations has been trapped for around 100,000 years, a Cambridge-led research team showed that carbon dioxide can be securely stored underground for far longer than the 10,000 years needed to avoid climatic impacts. Their new study shows that the critical component in geological carbon storage, the relatively impermeable layer of "cap rock" that retains the carbon dioxide, can resist corrosion from carbo dioxide-saturated water for at least 100,000 years. (N. Kampman, et al. "Observational evidence confirms modelling of the long-term integrity of CO_2-reservoir caprocks" *Nature Communications* 28 July 2016.) However, the Class VI regulations are designed to ensure that the carbon dioxide is contained in the permitted injection interval and monitoring of the site is required until the injected carbon dioxide no longer endangers underground sources of drinking water. The Commission made no change in response to this comment.

Permit Standards

The Texas-based organizations recommended that the Commission consider requiring operators to share real-time data with the Commission from the required continuous recording devices that will monitor injection pressure, rate, volume, and temperature of the CO_2 stream.

The Commission currently does not have the ability to receive such voluminous amounts of data. The Commission made no change in response to this comment.

The Texas-based organizations commented that, in the event of an emergency, the Commission should require operators to educate neighbors on appropriate safety procedures in response to an emergency and should explicitly require operators to notify neighbors. The Texas-based organizations recommended that the Commission revise §5.203(h)(3) to include notifying the facility's neighbors and individuals in the AOR and to require that the operator identify types of potential endangerment or emergencies and educate facility neighbors about appropriate responses to such events on an annual basis so that affected persons are prepared.

The Commission agrees with this comment and adopts §5.203(l)(3) with a change to require the safety plan to include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency, procedures for requesting assistance and for follow-up action to remove the public from an area of exposure, and provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO_2, the manner in which the public will be notified of an emergency, and steps to be taken in case of an emergency.

The Texas-based organizations commented that operators of Class VI wells should be required to have a certification or license with the state of Texas.

The Commission is unsure what type of certification or license would be required. Any geologic storage facility operator in Texas will be required to have a valid Organization Report (Form P-5) with adequate financial security and a permit for the facility prior to operation. In addition, §5.203(a)(5) states that, if required under Texas Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscience 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. The Commission made no change in response to this comment.

The Commission adopts amendments in §5.101 to remove language that references the Commission having jurisdiction over only a portion of the program.

The Commission amends §5.102 to add terms defined in HB 1284 and to add other terms included in the federal Class VI UIC regulations. The Commission adds a definition for "offshore" to reflect the definition included in HB 1284. The Commission adds definitions for "casing," "cementing," "Class VI well," "draft permit," "exempted aquifer," "flow rate," "formation," "injection well," "lithology," "packer," "permit," "plugging," "stratum," "surface casing," and "well injection" for consistency with the federal Class VI UIC regulations.

In §5.201, the Commission amends subsection (a) to reflect the change in jurisdiction under HB 1284 and to clarify that the Commission has jurisdiction over all geologic storage of anthropogenic carbon dioxide and the injection of anthropogenic carbon dioxide in the state, both onshore and offshore.

The Commission adopts amendments in §5.201(b) to add a title to the subsection and to include the factors that the Commission will consider when determining whether there is an increased risk to underground sources of drinking water such that a Class VI permit is required. As previously discussed in the preamble, the Commission adopts subsection (b)(2) with changes from the proposed text.

The Commission adopts new §5.201(c) to clarify that Subchapter B of Chapter 5 does not apply to the disposal of acid gas waste generated from oil and gas activities from a single lease, unit, field, or gas processing facility. Injection of acid gas that contains carbon dioxide and was generated as part of oil and gas processing may continue to be appropriately permitted as Class II injection. The potential need to transition from Class II to Class VI will be based on the increased risk to underground sources of drinking water related to significant storage of carbon dioxide in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk. The Commission will consider similar factors enumerated in §5.201(b) when determining whether there is such an increased risk. As previously discussed in the preamble, the Commission adopts subsection (c) with changes from the proposal.

The Commission amends §5.201(d), currently subsection (c), to add language from HB 1284 to clarify that this subchapter applies regardless of whether the well was initially completed for the purpose of injection and geologic storage of anthropogenic carbon dioxide or was initially completed for another purpose and is converted to the purpose of injection and geologic storage of anthropogenic carbon dioxide 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.

The Commission adopts new §5.201(e) to allow for the expansion of the areal extent of an aquifer exemption for a Class II enhanced recovery well for the exclusive purpose of Class VI injection for geologic storage in accordance with 40 Code of Federal Regulations (CFR) §146.4, relating to criteria for exempted aquifers. The Commission also adopts 40 CFR §144.7, relating to identification of underground sources of drinking water and exempted aquifers, and §146.4 by reference. Title 40 CFR §144.7 requires protection of aquifers and parts of aquifers that meet the definition of "underground source of drinking water" in 40 CFR §144.3. The section also provides for the designation of certain aquifers as exempt aquifers. Title 40 CFR §146.4 outlines the criteria an aquifer must meet for it to be designated exempt. The aquifer must not currently serve as a source of drinking water and must show it will not in the future serve as a source of drinking water because of one or more reasons listed in §146.4(b). The Commission adopts an effective date of September 20, 2022, as the date for which the federal regulations will be adopted by reference.

The Commission adopts new §5.201(f) to provide for 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. The Commission also adopts 40 CFR §146.95, relating to Class VI injection depth waiver requirements, by reference. Title 40 CFR §146.95 requires that an operator seeking a waiver submit a supplemental report with its permit application. The section also specifies the required elements of the supplemental report. As with subsection (e), the effective date is adopted as July 1, 2022. As previously discussed in the preamble, the Commission adopts subsection (f) with changes from the proposal.

The Commission adopts new §5.201(g) to state that the regulations do not apply to the injection of any CO_2 stream that meets the definition of a hazardous waste. As previously discussed in the preamble, the Commission adopts subsection (g) with changes from the proposal.

Finally, in §5.201, the Commission redesignates existing subsections (d) and (e) as new subsection (h) and (i), with no other changes.

In §5.202(a), the Commission adopts wording to require a storage operator to obtain a permit before engaging in certain activities and proposes new paragraph (2) regarding when injection may begin. As previously discussed in the preamble, the Commission adopts subsection (a)(1), as well as subsection (b)(1)(B), with changes from the proposal.

The Commission amends §5.202(d) to include language in the federal regulations at 40 CFR §124.5, relating to modification, revocation and reissuance, or termination of permits, and §144.39(a), relating to modification or revocation and reissuance of permits. New subsection (d)(1) states that permits issued pursuant to this subsection are subject to review by the Commission and allows any interested person to request that the Commission review a permit for one or more of several reasons. The request must be in writing and must contain facts to support the request. The Commission may review the permit if it determines that the request may have merit or at the Commission's initiative. As previously discussed in the preamble, the Commission adopts subsection (d)(1) with changes from the proposal.

The Commission adopts new subsection (d)(2), redesignated from current subsection (d)(1), to incorporate requirements of 40 CFR §144.39(a), relating to causes for modification or for revocation and reissuance. These causes include material and substantial alterations or additions to the permitted facility or activity, new information, new regulations, and modification of compliance schedules. The Commission adopts new language to state that if the director of the Oil and Gas Division or the director's delegate (hereinafter "director") tentatively decides to modify or revoke and reissue a permit, the director shall prepare a draft permit incorporating the proposed changes, and to clarify that the director may request additional information and, in the case of a modified permit, may require the submission of an updated application. In the case of revoked and reissued permits, the director shall require the submission of a new application. As previously discussed in the preamble, the Commission adopts subsection (d)(2)(A)(ii) and (iii) with changes from the proposal.

The Commission also adds language in subsection (d)(2)(A)(vii) to state that in a permit modification, only those conditions to be modified shall be reopened when a new draft permit is prepared and all other aspects of the existing permit shall remain in effect for the duration of the unmodified permit. When a permit is revoked and reissued under this section, the entire permit is reopened and subject to revision just as if the permit had expired and was being reissued. During any revocation and reissuance proceeding, the permittee shall comply with all conditions of the existing permit until a new final permit is reissued.

The Commission adopts new subsection (d)(2)(A)(viii) to clarify that, upon the consent of the permittee, the director may modify a permit to make the corrections or allowances for changes in the permit, without following the procedures of §5.202(e) and §5.204, to correct typographical errors; require more frequent monitoring or reporting by the permittee; change an interim compliance date in a schedule of compliance, provided the new date is not more than 120 days after the date specified in the existing permit and does not interfere with attainment of the final compliance date requirement; allow for a change in ownership or operational control of a facility where the director determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittees has been submitted to the director; change quantities or types of fluids injected which are within the capacity of the facility as permitted and, in the judgment of the director, would not interfere with the operation of the facility or its ability to meet the permit conditions; change construction requirements approved by the director pursuant to §5.206, provided that any such alteration shall comply with the requirements of this subchapter; amend a plugging and abandonment plan which has been updated under §5.203(k); or amend an injection well testing and monitoring plan, plugging plan, post-injection site care and site closure plan, or emergency and remedial response plan where the modifications merely clarify or correct the plan, as determined by the director.

The Commission adopts new §5.202(d)(2)(B) to make it consistent with the requirements in 40 CFR §144.40, relating to termination of permits, and includes the causes that could lead to termination of a permit during its term or to deny renewal of a permit consistent with 40 CFR §144.40. The new subparagraph also requires the director to issue an intent to terminate a permit, draft permit and fact sheet and provide for public comment in terminating any permit.

The Commission deletes existing subsection (d)(1)(A) - (E) because the reasons for modifying or revoking and reissuing a permit are enumerated in new subsection (d)(2).

The Commission adds new §5.202(d)(3) to state that the suitability of a facility location will not be considered at the time of permit modification or revocation and reissuance unless new information or standards indicate that a threat to human health or the environment exists which was unknown at the time of permit issuance.

The Commission renumbers current §5.202(d)(2) as new subsection (d)(4).

The Commission amends the title of §5.202 based on new subsection (e), which is proposed to comply with 40 CFR §124.6, relating to draft permits, and 40 CFR §124.8, relating to fact sheet. As previously discussed in the preamble, the Commission adopts subsection (e)(1)(C), (e)(2)(B), and (e)(2)(C)(ii) with changes from the proposal.

In §5.203, the Commission amends §5.203(a) to add requirements under 40 CFR §146.91(e), relating to reporting requirements, that operators of Class VI wells must submit geologic sequestration project information directly to EPA in an electronic format approved by EPA, regardless of whether a state has primacy for the Class VI program. Such data includes the permit application and associated data, as well as all required reports, submittals, and notifications. As of the time of this adoption, EPA is requiring the use of its Geologic Sequestration Data Tool (GSDT), which is a centralized, web-based system that receives, stores, and manages Class VI data, and satisfies the Class VI electronic reporting requirement. Whether or not the State has primacy for the Class VI UIC program, an applicant is required to submit to EPA all application and reporting information through the GSDT. The Commission plans to access Class VI information through the GSDT; the Commission will not develop or require the use of a separate online system.

The Commission adopts new wording in subsection (a)(1)(B) consistent with federal regulations at 40 CFR §144.32(a), relating to requirements for signatories to permit applications, and proposes new wording in subsection (a)(1)(C) consistent with federal regulations at 40 CFR §144.32(d), relating to certification of an application or report.

The Commission adopts new §5.203(a)(2)(B) to clarify that 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. The federal regulation at 40 CFR §144.31 relating to application for permit; authorization by permit, references "owner or operator;" however, the Commission holds the operator of the well, as identified by the Commission's Form P-4 (Certificate of Compliance and Transportation Authority), responsible.

The Commission adopts new §5.203(a)(2)(C) to add language consistent with 40 CFR §144.31(e)(6), relating to application for permit; authorization by permit, to require that an application include a listing of all relevant permits or construction approvals for the facility received or applied for under federal or state environmental programs.

The Commission adopts new §5.203(a)(2)(D) to reflect changes made by HB 1284 to Texas Water Code, §27.0461, to require that an applicant under this subchapter submit a letter of determination from TCEQ concluding that drilling and operating a Class VI injection well 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 Commission adopts new §5.203(a)(5) regarding the requirement that, if required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscience 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.

The Commission amends §5.203(d)(1)(A)(i)(III) to clarify that the initial delineation of the area of review must be estimated from initiation of injection until the plume movement ceases, for a minimum of 10 years after the end of the injection period proposed by the applicant. As previously discussed in the preamble, the Commission adopts subsection (d)(1)(A)(i), (d)(1)(A)(i)(III), and (d)(1)(A)(ii)(II) with changes from the proposal.

The Commission amends §5.203(e)(1)(B)(i) to clarify that the operator must ensure that injection wells are cased and the casing is cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements), in addition to the requirements of this section. As previously discussed in the preamble, the Commission adopts subsection (e)(1)(B)(v) and (vii), (e)(1)(C), and (e)(2)(D), as well as subsection (f)(2)(C) with changes from the proposal.

The Commission amends §5.203(h)(1)(B) to clarify that internal mechanical integrity must be demonstrated by pressure testing of the tubing casing annulus. As previously discussed in the preamble, the Commission adopts subsection (h)(1)(C) with changes from the proposal.

The Commission amends §5.203(h)(1)(D) to reflect the federal standard in 40 CFR §146.89, relating to mechanical integrity, and §146.90(e), relating to testing and monitoring requirements, that, at least once per year until the injection well is plugged, amended from the current text which says five years, the operator must confirm external mechanical integrity using an approved method.

The Commission amends §5.203(h)(1)(E) to clarify the requirement to test injection wells after any workover that disturbs the seal between the tubing, packer, and casing to verify the internal mechanical integrity of the tubing and long string casing.

The Commission amends §5.203(h)(2) to delete language regarding test frequency of five years to make the language consistent with the federal requirements in 40 CFR §146.89 and §146.90 for internal and external mechanical integrity testing.

The Commission amends §5.203(h)(2)(E) to clarify that some alternative test methods may need to be approved by the Administrator of EPA consistent with 40 CFR §146.89(e).

As previously discussed in the preamble, the Commission adopts §5.203(i)(1)(A) and (C) and (j)(2)(B) with changes from the proposal.

The Commission adds new §5.203(j)(2)(F) to require that a plan for monitoring, sampling, and testing after initiation of operation must include 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 consistent with federal requirements at 40 CFR §146.90(f), relating to injection well plugging.

The Commission amends §5.203(k)(1) to add the specific information required under 40 CFR §146.92(b), relating to injection well plugging, to be included in a well plugging plan.

As previously discussed in the preamble, the Commission adopts subsection (l)(3) with changes from the proposal.

The Commission amends §5.203(m) to add language to conform with the federal regulations. Following cessation of injection, the federal rules at 40 CFR §146.93, relating to post injection site care and site closure, require that the operator continue to conduct monitoring for at least 50 years. However, the director may approve, in consultation with EPA, an alternative timeframe other than the 50-year default, if the operator can demonstrate during the permitting process that an alternative timeframe is appropriate and ensures non-endangerment of USDWs. The federal rules require that the demonstration be based on significant, site-specific data and information and contain substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the alternative post injection site care timeframe. Current Commission rules do not include a 50-year default post injection site care period. To meet the minimum federal requirements, the Commission amends §5.203(m) to include the data and information required to make a demonstration that an alternative timeframe is appropriate and ensures non-endangerment of USDWs. The amendment would require additional effort for each Class VI permit application, but would provide a more appropriate, site-specific post injection site care timeframe. As previously discussed in the preamble, the Commission adopts subsection (m)(5) and (7)(C) with changes from the proposal.

In §5.204, the Commission amends the title from Notice and Hearing to Notice of Permit Actions and Public Comment Period; other amendments comply with the federal requirements at 40 CFR 124.10, public notice of permit actions and public comment period. The federal regulations require that the Commission provide notice of a draft permit. Therefore, the Commission deletes language regarding operator notice of an application under this subsection. The Commission also includes language stating that notice must include information satisfying the requirements of 40 CFR §124.10(d)(1). As previously discussed in the preamble, the Commission adopts subsection (a)(2), (a)(3)(A)(v), (vii), and (xi) through (x) with changes from the proposal.

The Commission also adopts new §5.204(a)(5) to require that the applicant identify whether any portions of the area of review encompass an environmental justice (EJ) or Limited English-Speaking Household community using U.S. Census Bureau 2018 American Community Survey data. If the area of review incudes an EJ or Limited English-Speaking Household community, the proposed new wording includes the actions that the applicant shall conduct. As previously discussed in the preamble, the Commission adopts subsection (a)(6) with changes from the proposal.

The Commission amends current §5.204(c) to redesignate it as subsection (b), to rename the subsection, and to make the requirements consistent with federal regulations at 40 CFR §124.12, relating to public hearings. New subsection (b)(1) clarifies that during the public comment period, an interested person may submit written comments on the draft permit and may request a hearing if one has not already been scheduled, that reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing may be required; and that 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. The Commission adopts new wording in subsection (b)(2) to state that the director must hold a public hearing whenever the director finds, on the basis of requests, a significant degree of public interest in a draft permit; and 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.

In §5.205, the Commission removes the $5 million cap in subsection (a)(4) and adopts other nonsubstantive changes. As previously discussed in the preamble, the Commission adopts subsection (c)(2)(C)(i) and subsection (d)(3) with changes from the proposal.

In §5.206, the Commission adopts amendments to make the section consistent with the federal requirements. The Commission adopts new subsection (a) consistent with 40 CFR §146.92(b) to require that all conditions applicable to all permits be incorporated into the permits either expressly or by reference. If incorporated by reference, a specific citation to these regulations must be given in the permit. The requirements are directly enforceable regardless of whether the requirement is a condition of the permit.

The Commission amends current §5.206(a), redesignated as subsection (b), to reorganize the subsection and to add new paragraph (8) requiring that an applicant provide a letter of determination from TCEQ concluding that drilling and operating an anthropogenic carbon dioxide 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, consistent with HB 1284.

The Commission amends current subsection §5.206(b), redesignated as subsection (c), to require written notice to the director 30 days, rather than 48 hours, 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, and to clarify that no such work may commence until approved by the director.

The Commission amends current §5.206(c)(2)(C), redesignated as subsection (d)(2)(C), to clarify that the Commission will 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. As previously discussed in the preamble, the Commission adopts subsection (c)(3) with changes from the proposal.

The Commission amends §5.206(d)(2)(D) to include a requirement that the operator 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. As previously discussed in the preamble, the Commission adopts subsection (d)(1)(B) with changes from the proposal.

The Commission amends current subsection §5.206(d), redesignated as subsection (e), to reorganize the subsection and to add a new paragraph (2) requiring that all permits specify requirements concerning the proper use, maintenance, and installation, when appropriate, of monitoring equipment or methods; required monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including when required, continuous monitoring; and applicable reporting requirements. Reporting shall be no less frequent than specified in this subchapter.

The Commission amends current §5.206(e)(4), redesignated as subsection (f), to add the term "significant" consistent with the language in federal regulations at 40 CFR §146.89(g). As previously discussed in the preamble, the Commission adopts subsection (e)(4) with changes from the proposal.

The Commission amends current subsection §5.206(h), redesignated as subsection (i), consistent with the federal requirements at 40 CFR §146.91(d) to require that operators notify the director in writing 30 days in advance of any planned workover, any planned stimulation activities, other than stimulation for formation testing conducted; and any other planned test of the injection well conducted by the permittee. As previously discussed in the preamble, the Commission adopts subsection (h)(2)(C) with changes from the proposal.

The Commission amends current subsection §5.206(j), redesignated as subsection (k), to add wording in paragraph (1)(B) to require that 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 at §5.202 of this subchapter, as appropriate. The Commission adds this language consistent with federal regulations at 40 CFR §146.93(a)(3), relating to post-injection site care and site closure. The Commission also amends paragraph (4) to clarify that notice by the operator to the director before closure must be in writing consistent with federal regulations at 40 CFR §146.93(d).

As previously discussed in the preamble, the Commission adopts subsection (k)(3)(C) and (k)(6)(A) and (C) with changes from the proposal.

The Commission amends current subsection §5.206(l), redesignated as subsection (m), to clarify that the operator must retain records collected during the post-injection storage facility care period for 10 years rather than five years following storage facility closure consistent with federal requirements at 40 CFR §146.93(h). As previously discussed in the preamble, the Commission adopts subsection (l)(5) with changes from the proposal.

The Commission amends current subsection §5.206(n), redesignated as subsection (o), to reorganize the subsection and to replace the term "suspended" with "terminated." The Commission also adopts new paragraph (2) consistent with federal regulations at 40 CFR Part 144, Subpart E, relating to permit conditions. Federal regulations require that permits for Class VI injection wells include conditions relating to the duty to comply, the need to halt or reduce activity not a defense in an enforcement action, the need take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance, the need to 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; the need for proper operation and maintenance, including effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures; the issuance of a permit does not convey any property rights of any sort, or any exclusive privilege; 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; the duty to provide information; the need to allow the Commission to enter and inspect any Class VI facility or where records are kept, have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit; 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; and the inclusion of a schedule of compliance, when appropriate.

The Commission also amends subsection §5.206(o) to add new paragraph (2)(G) to state that the permittee of a geologic storage well will be required to coordinate with any operator planning to drill through the area of review (AOR) to explore for oil and gas or geothermal resources. The Commission plans to designate the AOR of geologic storage projects on the GIS maps used by the Drilling Permits Section to alert the section of a drilling permit application for a well within the AOR. A condition will be included in the drilling permit requiring the drilling permittee to notify and coordinate with the permittee of the geologic storage project of its plans to drill.

The adopted amendments to §5.206(o)(2)(G) are made pursuant to the Commission's authority in Texas Natural Resources Code Chapters 85 and 91, as well as Water Code Chapter 27. As previously discussed in the preamble, the Commission adopts subsection (o)(2)(G) with changes from the proposal.

Texas Natural Resource Code, §85.042(b) requires the Commission to make and enforce rules either general in their nature or applicable to particular fields where necessary for the prevention of actual waste of oil or operations in the field dangerous to life or property. Section 85.046 defines "waste" to mean, "among other things, specifically includes: ... underground waste or loss, however caused and whether or not the cause of the underground waste or loss is defined in this section." Section 85.202 requires the Commission to include rules and orders to prevent waste of oil and gas in drilling and producing operations, to require wells to be drilled and operated in a manner that will prevent injury to adjoining property; and to prevent oil and gas and water from escaping from the strata in which they are found into other strata. Section 91.015 states that "Operators and drillers that drill for oil or gas shall use every possible precaution in accordance with the most approved methods to stop and prevent waste of oil, gas, or both oil and gas in drilling operations and shall not wastefully use oil or gas or allow oil or gas to leak or escape from natural reservoirs." Section 91.101 requires the Commission to adopt and enforce rules and orders and may issue permits relating to the drilling of exploratory wells and oil and gas wells to prevent pollution of surface water or subsurface water, Texas Water Code, §27.051 authorizes the Commission to issue a permit for the geologic storage of carbon dioxide if it finds, among other things, that the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation, that, with proper safeguards, both ground and surface fresh water can be adequately protected from carbon dioxide migration or displaced formation fluids, and that the injection of anthropogenic carbon dioxide will not endanger or injure human health and safety.

In §5.207, the Commission amends subsection (a)(2)(C)(iii) and (iv) to add mass and monthly annulus fluid volume to the items that the operator must include on the semi-annual report consistent with federal regulations at 40 CFR §146.91. As previously discussed in the preamble, the Commission adopts subsection (a)(2)(C)(ii) and (iii) with changes from the proposal.

The Commission amends §5.207(a)(2)(D) to move the language in subsection (a)(2)(D)(vi)(III) to new subsection (a)(3) and to clarify that the director will require such revisions after significant changes to the facility.

The Commission amends §5.207(b) to clarify that the results of internal mechanical integrity tests are to be reported on Form H-5, and to require that operators submit all required reports, submittals, and notifications under this subchapter to the director and to EPA in an electronic format approved by the EPA administrator.

The Commission adopts new subsection (c) to reflect federal regulations for signatories to reports at 40 CFR §144.32(b).

The Commission adopts new subsection (d) to require that all reports and other information be certified consistent with federal regulations at 40 CFR §144.32(d).

The Commission amends current subsection (c), redesignated as subsection (e), to clarify that the operator must retain records, including modeling inputs and data to support area of review calculations and integrity test results, for at least 10 years, rather than five years, consistent with federal regulations at 40 CFR §146.84(g), relating to area of review and corrective action.

The Commission adopts the amendments pursuant to House Bill 1284 (HB 1284, 87th Legislature, R.S., 2021), which gives the Railroad Commission of Texas sole jurisdiction over carbon sequestration wells; 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, as enacted by SB 1387 (81st Texas Legislature, R.S., 2009), relating to authorization for multiple or alternative uses of wells; Texas Water Code, Chapter 27, Subchapter C-1, as enacted by SB 1387 (81st Texas Legislature, R.S., 2009), 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; and Texas Water Code, Chapter 120, as enacted by SB 1387 (81st Texas Legislature, R.S., 2009), 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; and Texas Water Code, Chapters 27 and 120.

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

SUBCHAPTER A. GENERAL PROVISIONS

§5.101. Purpose.

The purpose of this chapter is to implement the [~~portion of the~~] state program for geologic storage of anthropogenic CO_2 [~~over which the Railroad Commission has jurisdiction~~] consistent with state and federal law related to protection of underground sources of drinking water.

§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** [**~~actions proposed by an application for a geologic storage facility permit or an amendment or modification of an existing geologic storage facility permit,~~**] 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 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 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_2stream.

(7) Carbon dioxide (CO_2) stream--CO_2 that has been captured from an emission source, 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 [~~Code of Federal Regulations~~] 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) [~~(8)~~] Commission--A quorum of the members of the Railroad Commission of Texas convening as a body in open meeting.

(13) [~~(9)~~] 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 is capable of limiting fluid movement from an injection zone~~**] **that acts as a barrier to fluid movement**.

(14) [~~(10)~~] 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) [~~(11)~~] Delegate--The person authorized by the director to take action on behalf of the Railroad Commission of Texas under this chapter.

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

(17) [~~(13)~~] 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) [~~(14)~~] 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) 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.

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

(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.

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

(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.

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

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

(27) [~~(18)~~] Geologic storage--The long-term containment of anthropogenic CO_2 in **subsurface geologic formations** [**~~a reservoir~~**].

(28) [~~(19)~~] Geologic storage facility or storage facility--The underground **geologic formation**[**~~reservoir~~**], 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[~~, and pressure fronts~~]. 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.

(29) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in pore space, such as evidence of a currently valid lease or a recorded deed conveying a fee interest in the pore space.

(30) [~~(20)~~] 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.

(31) Injection well--A well into which fluids are injected.

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

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

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

(35) [~~(21)~~] 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.

<u>(36)</u> [~~(22)~~] 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.

<u>(37) Offshore--The area in the Gulf of Mexico seaward of the coast that is within three marine leagues of the coast.</u>

<u>(38)</u> [~~(23)~~] Operator--A person, acting for <u>itself</u> [~~himself~~] 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.

<u>(39) Packer--A device lowered into a well to produce a fluid-tight seal.</u>

<u>(40) Permit--An authorization, license, or equivalent control document issued by the Commission to implement the requirements of **this** chapter.</u>

<u>(41)</u> [~~(24)~~] Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

<u>(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.</u>

<u>(43)</u> [~~(25)~~] 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.

<u>(44)</u> [~~(26)~~] 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.

<u>(45)</u> [~~(27)~~] Reservoir--A natural or artificially created subsurface **[~~sedimentary~~]** stratum, formation, aquifer, cavity, void, or coal seam.

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

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

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

(49) [~~(29)~~] Underground source of drinking water (USDW)--An aquifer or its portion which is not an exempt aquifer as defined in 40 CFR [~~Code of Federal Regulations~~] §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.

(50) Well injection--The subsurface emplacement of fluids through a well.

(51) [~~(30)~~] 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.

(52) [~~(31)~~] 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.

SUBCHAPTER B. GEOLOGIC STORAGE AND ASSOCIATED INJECTION OF ANTHROPOGENIC CARBON DIOXIDE (CO_2)

§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[~~, and the injection of anthropogenic CO_2 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. A reservoir that may be productive means an identifiable geologic unit that has had production in the past, which is similar to productive or previously productive reservoirs along the same or a similar trend, or potentially contains oil, gas, or geothermal resources based on analysis of geophysical and/or seismic data~~].

(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** **~~Commission~~**.

(3) This [~~Additionally, 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 **~~a single~~** lease**s**, unit**s**, field**s**, 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 [~~**listed in subsection (b)(2)(A), (B), and (D) through (I) of this section.**~~]**:**

(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) [~~(c)~~] 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) [~~(d)~~] 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.

(i) [~~(e)~~] 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.

§5.202. Permit Required, and Draft Permit and Fact Sheet.

(a) Permit required.

(1) A person shall [~~may~~] not begin drilling or operating an anthropogenic CO_2 injection well for geologic storage **regulated under this subchapter** or constructing or operating a geologic storage facility regulated under this subchapter without first obtaining the necessary permits [~~permit(s)~~] from the Commission. Following receipt of a geologic storage facility permit issued under this subchapter, the storage operator shall obtain a permit to drill, deepen, or convert a well for storage purposes in accordance with §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back).

(2) A person may not begin injection until:

(A) construction of the well is complete;

(B) the operator has submitted to the director notice of completion of construction;

(C) the Commission has inspected or otherwise reviewed the injection well and finds it is in compliance with the conditions of the permit; and

(D) the director has issued a permit to operate the injection well.

(b) Permit amendment.

(1) An operator must file an application to amend an existing geologic storage facility permit with the director:

(A) prior to expanding the areal extent of the storage reservoir;

(B) prior to increasing the permitted injection pressure **or injection rate**;

(C) prior to adding injection wells; or

(D) at any time that conditions at the geologic storage facility materially deviate from the conditions specified in the permit or permit application.

(2) Compliance with plan amendments required by this subchapter does not necessarily constitute a material deviation in conditions requiring an amendment of the permit.

(c) Permit transfer. An operator may transfer its geologic storage facility permit to another operator if the requirements of this subsection are met. A new operator shall [~~may~~] not assume operation of the geologic storage facility without a valid permit.

(1) Notice. An applicant must submit written notice of an intended permit transfer to the director at least 45 days prior to the date the transfer of operations is proposed to take place, unless such action could trigger U. S. Securities and Exchange Commission fiduciary and insider trading restrictions and/or rules.

(A) The applicant's notice to the director must contain:

(i) the name and address of the person to whom the geologic storage facility will be sold, assigned, transferred, leased, conveyed, exchanged, or otherwise disposed;

(ii) the name and location of the geologic storage facility and a legal description of the land upon which the storage facility is situated;

(iii) the date that the sale, assignment, transfer, lease conveyance, exchange, or other disposition is proposed to become final; and

(iv) the date that the transferring operator will relinquish possession as a result of the sale, assignment, transfer, lease conveyance, exchange, or other disposition.

(B) The person acquiring a geologic storage facility, whether by purchase, transfer, assignment, lease, conveyance, exchange, or other disposition, must notify the director in writing of the acquisition as soon as it is reasonably possible but not later than five business days after the date that the acquisition of the geologic storage facility becomes final. The director shall [~~may~~] not approve the transfer of a geologic storage facility permit until the new operator provides all of the following:

(i) the name and address of the operator from which the geologic storage facility was acquired;

(ii) the name and location of the geologic storage facility and a description of the land upon which the geologic storage facility is situated;

(iii) the date that the acquisition became or will become final;

(iv) the date that possession was or will be acquired; and

(v) the financial assurance required by this subchapter.

(2) Evidence of financial responsibility. The operator acquiring the permit must provide the director with evidence of financial responsibility satisfactory to the director in accordance with §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).

(3) Transfer of responsibility. An operator remains responsible for the geologic storage facility until the director approves in writing the sale, assignment, transfer, lease, conveyance, exchange, or other disposition and the person acquiring the storage facility complies with all applicable requirements.

(d) Modification, revocation and reissuance, or termination [~~cancellation, or suspension~~] of a geologic storage facility permit.

(1) Permit review. Permits are subject to review by the Commission. Any interested person may request that the Commission review a permit issued under this subchapter for one of the reasons set forth in paragraph (2) of this subsection. All requests must be in writing and must contain facts or reasons supporting the request. If the Commission determines that the request may have merit or at the Commission's initiative for one or more of the reasons set forth in paragraph (2) of this subsection, the Commission may review the permit. [**~~An interested person includes:~~**

~~(A) the storage operator;~~

~~(B) local governments having jurisdiction over land within the area of review; or~~

~~(C) any person who has suffered or will suffer actual injury or economic damage.~~]

(2) [~~(1)~~]Action by the Commission [~~General~~]. The director may modify, revoke and reissue [~~suspend~~], or terminate [~~cancel~~] a geologic storage facility permit after notice and opportunity for hearing under any of the following circumstances. [~~:~~]

(A) Causes for modification or for revocation and reissuance. The following may be causes for revocation and reissuance as well as modification:

(i) Alterations. There are material and substantial alterations or additions to the permitted facility or activity which occurred after permit issuance that justify the inclusion of permit conditions that are different from or absent in the existing permit.

(ii) New information. The director has received **new material** information that was not available at the time of permit issuance and would have justified the inclusion of different permit conditions at the time of issuance. This may include any increase greater than the permitted CO_2 storage volume, and/or changes in the chemical composition of the CO_2 stream **that in the judgment of the director, would interfere with the operation of the facility or its ability to meet the permit conditions.**

(iii) New regulations. The standards or regulations on which the permit was based have been **materially** changed by promulgation of new or amended standards or regulations or by judicial decision after the permit was issued.

(iv) Compliance schedules. The director determines good cause exists for modification of a compliance schedule, such as an act of God, strike, flood, or materials shortage, or other events over which the permittee has little or no control and for which there is no reasonably available remedy.

(v) Basis for permit modification. The director shall modify the permit whenever the director determines that permit changes are necessary based on:

(I) a re-evaluation under §5.203(d) of this title (relating to Application Requirements);

(II) any amendments to the testing and monitoring plan under §5.203(j) of this subchapter;

(III) any amendments to the injection well plugging plan under §5.203(k) of this title;

(IV) any amendments to the post-injection site care and site closure plan under §5.203(m) of this title;

(V) any amendments to the emergency and remedial response plan under §5.203(l) of this title;

(VI) a review of monitoring and/or testing results conducted in accordance with permit requirements;

(VII) cause exists for termination under subparagraph (B) of this paragraph, and the director determines that modification or revocation and reissuance is appropriate;

(VIII) the director has received notification of a proposed transfer of the permit; or

(IX) a determination that the fluid being injected is a hazardous waste as defined in 40 CFR §261.3 either because the definition has been revised, or because a previous determination has been changed.

(vi) If the director tentatively decides to modify or revoke and reissue a permit, the director shall prepare a draft permit incorporating the proposed changes. The director may request additional information and, in the case of a modified permit, may require the submission of an updated application. In the case of revoked and reissued permits, the director shall require the submission of a new application.

(vii) In a permit modification, only those conditions to be modified shall be reopened when a new draft permit is prepared. All other aspects of the existing permit shall remain in effect for the duration of the existing permit. When a permit is revoked and reissued under this section, the entire permit is reopened just as if the permit had expired and was being reissued. During any revocation and reissuance proceeding, the permittee shall comply with all conditions of the existing permit until a new final permit is reissued.

(viii) Upon the consent of the permittee, the director may modify a permit to make the corrections or allowances for **minor** changes in the permit, without following the procedures of subsection (e) of this section, and §5.204 of this title (relating to Notice of Permit Actions and Public Comment Period), to:

(I) correct typographical errors;

(II) require more frequent monitoring or reporting by the permittee;

(III) change an interim compliance date in a schedule of compliance, provided the new date is not more than 120 days after the date specified in the existing permit and does not interfere with attainment of the final compliance date requirement;

(IV) allow for a change in ownership or operational control of a facility where the director determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittees has been submitted to the director;

(V) change quantities or types of fluids injected which are within the capacity of the facility as permitted and, in the judgment of the director, would not interfere with the operation of the facility or its ability to meet the permit conditions;

(VI) change construction requirements approved by the director pursuant to §5.206 of this title (relating to Permit Standards), provided that any such alteration shall comply with the requirements of this subchapter;

(VII) amend a plugging and abandonment plan which has been updated under §5.203(k) of this title; or

(VIII) amend an injection well testing and monitoring plan, plugging plan, post-injection site care and site closure plan, or emergency and remedial response plan where the modifications merely clarify or correct the plan, as determined by the director.

(B) Termination of permits.

(i) The following may be causes to terminate a permit during its term, or deny a permit renewal application:

(I) the permittee's failure to comply with any condition of the permit or applicable Commission orders or regulations;

(II) the permittee's failure in the application or during the permit issuance process to disclose fully all relevant facts, or the permittee's misrepresentation of any relevant facts at any time;

(III) fluids are escaping or are likely to escape from the injection zone;

(IV) USDWs are likely to be endangered as a result of the continued operation of the geologic storage facility; or

(V) a determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination.

(ii) The director shall follow the applicable procedures in subsection (e) of this section, and §5.204 of this title, in terminating any permit under this section.

(iii) If the director tentatively decides to terminate a permit under this subchapter, where the permittee objects, the director shall issue a notice of intent to terminate. A notice of intent to terminate is a type of draft permit.

[~~(A) There is a material change in conditions in the operation of the geologic storage facility, or there are material deviations from the information originally furnished to the director. A change in conditions at a facility that does not affect the ability of the facility to operate without causing an unauthorized release of CO_2 and/or formation fluids is not considered to be material;~~]

[~~(B) Underground sources of drinking water are likely to be endangered as a result of the continued operation of the geologic storage facility;~~]

[~~(C) There are substantial violations of the terms and provisions of the permit or of applicable Commission orders or regulations;~~]

[~~(D) The operator misrepresented material facts during the permit application or issuance process; or~~]

[~~(E) Fluids are escaping or are likely to escape from the injection zone.~~]

(3) Facility siting. Suitability of the facility location shall not be considered at the time of permit modification or revocation and reissuance unless new information or standards indicate that a threat to human health or the environment exists which was unknown at the time of permit issuance.

(4) [~~(2)~~] Emergency shutdown. Notwithstanding the provisions of paragraph (2) [~~(1)~~] of this subsection, in the event of an emergency that threatens endangerment to USDWs [~~underground sources of drinking water~~] or to life or property, or an imminent threat of uncontrolled release of CO_2 , the director may immediately order suspension of the operation of the geologic storage facility until a final order is issued pursuant to a hearing, if any.

(e) Draft permit and fact sheet.

(1) Draft permit; notice of intent to deny.

(A) Once a geologic storage facility permit application is complete, the director shall decide whether to prepare a draft permit or to deny the application.

(B) If the director tentatively decides to deny the permit application, the director shall issue a notice of intent to deny. A notice of intent to deny the permit application is a type of draft permit which follows the same procedures as any draft permit prepared under this section. If the director's final decision is that the tentative decision to deny the permit application was incorrect, the director shall withdraw the notice of intent to deny and proceed to prepare a draft permit.

(C) If the director decides to prepare a draft permit, the draft permit shall contain the permit conditions required under §5.206 of this title (relating to Permit Standards). **If the director is issuing a denial, the permit conditions are not required.**

(2) Fact sheet.

(A) The director shall prepare a fact sheet for every draft permit. The fact sheet shall briefly set forth the principal facts and the significant factual, legal, methodological and policy questions considered in preparing the draft permit.

(B) The director shall send this fact sheet to the applicant and, on request, to any other person. **The director shall post the fact sheet on the Commission's website.**

(C) The fact sheet shall include, when applicable:

(i) a brief description of the type of facility or activity which is the subject of the draft permit;

(ii) the **source and** quantity of CO_2 proposed to be injected and stored;

(iii) the reasons why any requested variances or alternatives to required standards do or do not appear justified;

(iv) a description of the procedures for reaching a final decision on the draft permit including:

(I) the beginning and ending dates of the comment period;

(II) the address where comments will be received;

(III) The date, time, and location of the storage facility permit hearing, if a hearing has been scheduled; and

(IV) any other procedures by which the public may participate in the final decision; and

(v) the name and telephone number of a person to contact for additional information.

§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 [~~one copy of~~] 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 [~~the~~] appropriate district office [~~office(s)~~] 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. [~~If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practices Act, or Chapter 1002, relating to Texas Geoscientists Practices Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this section and must affix the appropriate seal on the resulting reports of such evaluations.~~]

(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 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.

(3) Application completeness. The Commission shall [~~may~~] 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 [~~location(s)~~] of any injection wells [~~well(s)~~] and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR [~~area of review~~].

(2) The applicant must show within the AOR [~~area of review~~] on the map the number or name and the location of:

(A) all known artificial penetrations through the confining zone, including 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 [~~area of review~~] that indicate the general vertical and lateral limits of all USDWs [~~underground sources of drinking water~~] within the AOR [~~area of review~~], 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 [~~area of review~~] 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 [~~underground sources of drinking water~~] within the AOR [~~area of review~~].

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

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

(A) Delineation of AOR [~~area of review~~].

(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 [~~an underground source of drinking water~~] 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 [~~**plume**~~] movement **of the CO_2 plume and associated pressure front stabilizes** [~~**ceases, for a minimum of [to] 10 years after the end of the injection period proposed by the applicant**~~].

(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 [~~area of review~~], 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 [~~area of review~~] 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 [~~underground sources of drinking water~~] or allow the injected fluids or formation fluids to escape the permitted injection zone. The applicant must perform corrective action on all wells and underground mines in the AOR [~~area of review~~] 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** **~~Area of review~~** and corrective action plan. As part of an application, the applicant must submit an AOR [~~area of review~~] and corrective action plan that includes the following information:

(A) the method for delineating the AOR [~~area of review~~], 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 [~~area of review~~], a description of:

(i) the minimum frequency 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 [~~area of review~~] during the life of the geologic storage facility;

(ii) how monitoring and operational data will be used to re-evaluate the AOR [~~area of review~~]; and

(iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR [~~area of review~~] 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 [~~area of review~~];

(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 [~~underground sources of drinking water~~];

(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 [~~underground source of drinking water~~] 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 **to** [~~**through**~~] 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 [~~underground sources of drinking water~~] 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 [~~underground sources of drinking water~~] 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 [~~**mechanical**~~] 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, and maximum proposed volume **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 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 [~~If the fracture pressures are determined through calculation, the~~] Commission will include in any permit it might issue a limit of 90% of the [~~calculated~~] 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 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.

(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 [~~every five years~~], the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) [~~that the injected fluids are confined to the injection~~

~~zone~~] 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 plan must include a schedule for the performance of a series of tests at a minimum frequency of five years.~~] 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) [~~§5.206(e)~~] 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 [~~source(s)~~] 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 [~~underground sources of drinking water~~].

(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 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 annually. Corrosion monitoring may be accomplished by:

(i) analyzing coupons of the well construction materials in contact with the CO_2stream;

(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 [~~an underground source of drinking water~~] within the AOR [~~area of review~~] 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 [~~area of review~~], 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 [~~area of review~~] 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; [~~and~~]

(F) 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

(G) [~~(F)~~] additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR [~~area of review~~] evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs [~~underground sources of drinking water~~] 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 [~~area of review~~], regardless of whether or not corrective action in the AOR [~~area of review~~] 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 [~~underground sources of drinking water~~] 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**;**[~~, and~~]

(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) [~~(1)~~] the pressure differential between pre-injection and predicted post-injection pressures in the injection zone;

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

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

(5) [~~(4)~~] a proposed schedule for submitting post-injection storage facility care monitoring results to the **director[~~division~~]**; [~~and~~]

(6) [~~(5)~~] 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 [~~cessation of migration~~]**;

(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 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 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 [~~and Hearing~~].

[~~(a) Placement of copy of application for public inspection. The applicant must make a complete copy of the permit application available for the public to inspect and copy by filing a copy of the application with the County Clerk at the courthouse of each county where the storage facility is to be located, or if approved by the director, at another equivalent public office. The applicant also must provide an electronic copy of the complete application to enable the Commission to place the copy on the Railroad Commission Internet website. The applicant must file any subsequent revision of the application with the County Clerk or other approved public office and must file at the Commission an electronic copy of the updated application at the same time the applicant files the revision at the Commission.~~]

(a) [~~(b)~~] 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) [~~(1)~~] General notice by publication. The Commission shall [~~To give general notice to local governments and interested or affected persons, the applicant must~~] publish notice of a draft permit [~~the application for an original or amended storage facility permit no later than the date the application is mailed to or filed with the director. The applicant must use the appropriate form of notice, include the information as set forth in subparagraph (A) or (B) of this paragraph, and cause the notice to be published~~] once a week for three consecutive weeks in a [~~each~~] newspaper of general circulation in each county where the storage facility is located or is to be located. T**he Commission shall also post**

notice of a draft permit on the Commission's website. [~~The applicant must file proof of publication of the notice with the application.~~]

[~~(A) Form for notice by publication of an application for an anthropogenic CO_2 geologic storage facility permit.~~]

[~~Figure: 16 TAC §5.204(b)(1)(A)~~]

[~~(B) Form for notice by publication of an application for amendment of an existing CO_2 geologic storage facility permit.~~]

[~~Figure: 16 TAC §5.204(b)(1)(B)~~]

[~~(C) The applicant must submit proof of publication of notice in the following form:~~]

[~~Figure: 16 TAC §5.204(b)(1)(C)~~]

(3) [~~(2)~~] Methods of notification. The Commission shall give notice by the following methods: [~~Individual notice.~~]

(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 State 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;

[~~(A)~~] [~~Persons to notify. By no later than the date the application is mailed to or filed with the director, the applicant must give notice of an application for a permit to operate a CO_2 storage facility, or to amend an existing storage facility permit to:~~]

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

(v) [~~(ii)~~] each leaseholder **and interest owner** of minerals lying above or below the proposed **geologic storage facility** **[~~storage reservoir~~]**;

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

(vii) [~~(iv)~~] each owner or leaseholder of any portion of the surface overlying the proposed **geologic storage facility** **[~~storage reservoir~~]** and the adjoining area of the outermost boundary of the proposed geologic storage facility;

(viii) [~~(v)~~] the clerk of the county or counties where the proposed **geologic** storage facility is located **or is proposed to be located**;

(ix) [~~(vi)~~] the city clerk or other appropriate city official where the proposed **geologic** storage facility is located within city limits; [~~and~~]

(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) 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

(xii) [~~(vii)~~] 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) [~~(B)~~] Content of notice. Individual notice must consist of:

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

(B) [~~(ii)~~] a description of the geologic storage facility location;

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

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

(E) [~~(iv)~~] a statement that:

(i) [~~(I)~~] affected persons may protest the application;

(ii) [~~(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) [~~(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) [~~(3)~~] Individual notice by publication. The applicant must make diligent efforts to ascertain the name and address of each person identified under paragraph (3)(A) [~~(2)(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) [~~(2)(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) [~~(1)~~] 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** [~~**Proficiency (LEP) area**~~] **community** using **the most recent** U.S. Census Bureau [~~**2018**~~] American Community Survey data. If the AOR incudes an EJ or **Limited English-Speaking Household community** [~~**LEP area**~~], the applicant shall conduct enhanced public outreach activities to these communities. Efforts to include EJ and **Limited English-Speaking Household [~~LEP~~]** 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) [~~(c)~~] Public comment and hearing [~~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) [~~(1)~~] 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) [~~(b)~~] 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. [~~The Commission must give notice of the 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.~~]

(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) [~~(2)~~] 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) [~~(b)~~] of this section or from any other affected person, the director may administratively approve the application.

(4) [~~(3)~~] 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.

§5.205. 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.

[~~(4) The anthropogenic CO_2 storage trust fund shall be capped at $5,000,000.~~]

(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 [~~area of review~~], regardless of whether corrective action in the AOR [~~area of review~~] is phased.

(c) Financial assurance.

(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 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 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 [~~may~~] 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[**~~, exclusive of plugging costs for any well or wells at the facility,~~**] at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit;

(ii) A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice [~~Practices~~] 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 [~~Practices~~] 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.

(E) The operator of a geologic storage facility must provide to the director annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR [~~area of review~~] 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 operator must provide to the director upon request an adjustment of the cost estimate if the director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging and post-injection storage facility care and closure.

(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.

(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** [~~**90**~~] days.

§5.206. Permit Standards.

(a) 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.

(b) [~~(a)~~] 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 [~~underground sources of drinking water~~] 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 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;

(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 [~~zone(s)~~] 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 [~~underground sources of drinking water~~];

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

(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);

(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;

(9) [~~(8)~~] 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;

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

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

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

(c) [~~(b)~~] 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 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 [~~48 hours, and obtain the director's approval,~~] prior to conducting any well workover that involves running tubing and setting packers [~~packer(s)~~], 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. [~~**No such work may commence until approved by the director.**~~]

(d) [~~(c)~~] Operating a geologic storage facility.

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

(2) Operating criteria.

(A) Injection between the outermost casing protecting USDWs [~~underground sources of drinking water~~] 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 [~~underground sources of drinking water~~]. 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) [~~(d)~~] 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 [~~area of review~~] evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs [~~underground sources of drinking water~~].

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

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

(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 [~~underground sources of drinking water~~] resulting from the injection activity.

(g) [~~(f)~~] **AOR** ~~**Area of review**~~ and corrective action. Notwithstanding the requirement in §5.203(d)(2)(B)(i) of this title to perform a re-evaluation of the AOR [~~area of review~~], at the frequency specified in the AOR [~~area of review~~] and corrective action plan or permit, 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:

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

(2) identify all wells in the re-evaluated AOR [~~area of review~~] that require corrective action;

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

(4) submit an amended AOR [~~area of review~~] and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR [~~area of review~~] and corrective action plan is needed.

(h) [~~(g)~~] 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.

(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. If an operator obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to USDWs [~~underground sources of drinking water~~], the operator must:

(A) immediately cease injection;

(B) take all steps reasonably necessary to identify and characterize any release;

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

(D) implement the approved emergency and remedial response plan.

(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 [~~underground sources of drinking water~~].

(i) [~~(h)~~] 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 [~~test~~] and submit notice at least 48 hours in advance of any actual activity. Such activities shall [~~testing or logging. Testing and logging may~~] not commence before the end of the 30 days [~~48-hour period~~] unless authorized by the director.

(j) [~~(i)~~] 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) [~~(j)~~] 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 [~~underground sources of drinking water~~].

(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 [~~underground sources of drinking water~~]. 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 [~~underground sources of drinking water~~];

(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 [~~underground sources of drinking water~~];

(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.

(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**,** [~~**and**~~] 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) [~~(k)~~] 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) [~~(l)~~] Retention of records. The operator must retain for 10 [~~five~~] years following storage facility closure records collected during the post-injection storage facility care period. The operator must 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) [~~(m)~~] 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)[~~(n)~~] 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 [~~underground sources of drinking water~~]. Permits issued under this subchapter continue in effect until revoked, modified, or terminated [~~suspended~~] 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 may, when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title.

(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.

§5.207. Reporting and Record-Keeping.

(a) 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 [~~the test(s) and the method(s)~~] 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 to the appropriate district office 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.

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

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

(vii) [~~(vi)~~] the results of monitoring prescribed under §5.206(e) [~~§5.206(d)~~] 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 [~~area of review~~] 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 [~~area of review~~] 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) The operator must maintain and update required plans in accordance with the provisions of this subchapter.

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

(-a-) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR [~~area of review~~] 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

(-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) 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.

[~~(III) The director may require the revision of any required plan whenever the director determines that such a revision is necessary to comply with the requirements of this title.~~]

(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 whenver 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) [~~(c)~~] Record retention. The operator must retain all wellhead pressure records, metering records, and integrity test results for at least 10 [~~five~~] years. 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) [~~§5.206(j)(7)~~] of this title.

This agency hereby certifies that the rules as adopted have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on August 30, 2022.

Filed with the Office of the Secretary of State on August 30, 2022.

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