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RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

MEMORANDUM

TO: Chairman Christi Craddick
Commissioner Wayne Christian
Commissioner Jim Wright

FROM: Haley Cochran, Assistant General Counsel
Office of General Counsel

THROUGH: Alexander C. Schoch, General Counsel

DATE: January 29, 2025

SUBJECT: Adoption of new 16 TAC §3.82, relating to Brine Production Projects and amendments to various other rules in Chapter 3

Attached is Staff's recommendation to adopt new 16 Texas Administrative Code §3.82, relating to Brine Production Projects and Associated Brine Production Wells and Class V Spent Brine Return Injection Wells. Staff also recommends the adoption of corresponding amendments to various rules in Chapter 3.

New Section 3.82 implements the requirements of Senate Bill 1186 (88th Legislature, Regular Session, 2023), which amended Texas Water Code §27.036 to clarify the Commission's jurisdiction over brine mining under state law. The Commission has jurisdiction over brine mining by injecting fluid to dissolve subsurface salt formations and then extracting the salts from the resulting artificial brines. The bill clarified that the Commission's jurisdiction over brine mining includes the authority to regulate brine production wells and brine injection wells ("spent brine return injection wells") used for lithium mining, which requires re-injecting naturally occurring brines into the formation from which they were produced after the extraction of minerals. The new rule will allow the Commission to seek primary enforcement authority from the EPA for the spent brine return injection wells, which are Class V UIC wells.

On October 15, 2024, the Commission approved the publication of the new rule and amendments in the Texas Register for a public comment period, which ended on December 2, 2024. Staff recommends that the Commission adopt new §3.82 with changes to the proposed text published in the November 1, 2024, issue of the Texas Register (49 TexReg 8649). The recommended changes are described in the attached adoption preamble.

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

The Railroad Commission of Texas (Commission) adopts amendments to §§3.1, 3.5, 3.7, 3.12, 3.13, 3.16, 3.17, 3.32, 3.36, 3.73, 3.78, and 3.81 relating to Organization Report; Retention of Records; Notice Requirements; Application To Drill, Deepen, Reenter, or Plug Back; Strata To Be Sealed Off; Directional Survey Company Report; Casing, Cementing, Drilling, Well Control, and Completion Requirements; Log and Completion or Plugging Report; Pressure on Bradenhead; Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes; Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas; Pipeline Connection; Cancellation of Certificate of Compliance; Severance; Fees and Financial Security Requirements; and Class III Brine Mining Injection Wells, and adopts new §3.82, relating to Brine Production Projects and Associated Brine Production Wells and Class V Spent Brine Return Injection Wells. Section 3.82 is adopted with changes to the proposed text as published in the November 1, 2024, issue of the Texas Register (49 TexReg 8649). The remaining rules are adopted without changes to the proposed text and will not be republished.

The Commission adopts the amendments and new rule to implement the provisions of Senate Bill (SB) 1186 (88th Legislature, Regular Session, 2023), relating to the regulation by the Commission of brine mining.

SB 1186 added a definition of "brine mining" to Texas Water Code §27.036, to clarify the Commission's jurisdiction over brine mining under state law. The bill also instructed the Commission to seek primacy from the EPA for Class V injection wells designed to inject spent brine into the same formation from which it was withdrawn after the extraction of minerals. Additionally, the bill clarified that the Commission's jurisdiction over brine mining includes the authority to regulate brine production wells and brine injection wells. The Commission proposed §3.82 to create a regulatory scheme for these projects and wells. Amendments were proposed in other sections of Chapter 3 to ensure consistency with the new rule.

The Commission received comments on the proposal from seven entities, three of which were associations (Sierra Club, Lone Star Chapter ("Sierra Club"), Texas Land & Mineral Owners Association ("TLMA"), and Texas Oil & Gas Association ("TXOGA")). Coghlan Crowson, LLP ("Coghlan Crowson"), Standard Lithium, Ltd. ("Standard Lithium"), TerraVolta Resources ("TerraVolta"), and Texas Brine Company, LLC ("Texas Brine") also submitted comments. The Commission appreciates the input from these commenters.

TXOGA commented regarding the Commission's proposed amendments to §3.7, which require that new oil and gas wells be cased and cemented to isolate brine resources penetrated by the wellbore. TXOGA also commented regarding the Commission's proposed amendments to §3.13, which revise the definition of "productive zone" to include any stratum known to contain brine resources in commercial quantities in the area and requires that casing be cemented across and above all productive zones. TXOGA noted this requirement could potentially add significant costs to new oil and gas wells drilling through a formation containing brine and asked the Commission to clarify how the requirement will be implemented.

The Commission intends that whenever hydrocarbons, brine, or geothermal resources are encountered in any well drilled for oil, gas, brine, or geothermal resources that the fluid be confined in its original stratum until it can be produced and utilized without waste. Section 3.13 requires that casing be cemented across and above all productive zones. The Commission finds that these requirements are necessary to protect the interests of producers and owners of oil, gas, brine, and geothermal resources. Although the Commission agrees that this requirement may result in increased costs, the costs will be no greater than if a new oil or gas reservoir is discovered. The Commission will add brine fields to the §3.13 list on the Commission's website. The Commission made no change in response to this comment.

TXOGA also commented generally regarding terms used in the proposed amendments and proposed new §3.82, stating that the terms and definitions are inconsistent with terms and definitions in other rules in Chapter 3. Specifically, TXOGA asked the Commission to conform the definitions of "commission" and "director" proposed in §3.82(b) with how those terms are defined elsewhere in Chapter 3. TXOGA also noted that terms from §§3.13 and 3.14 should be removed from §3.82 because §3.82 references those rules, which sufficiently explain the terms used therein.

The Commission agrees with the comment regarding the definition of "Commission" and adopts the definition of "Commission" consistent with the definition in §4.110(22) of this title, relating to Definitions. The Commission does not agree with the comment regarding the definition of "Director" as the definition in §3.82 simply clarifies that the Oil and Gas Division is part of the Railroad Commission of Texas.

TXOGA recommended deleting the definitions for casing, cementing, and surface casing because wells regulated under §3.82 must comply with §3.13 which already describes those terms. Similarly, TXOGA recommended deleting the definitions for plugging and plugging record because wells regulated under §3.82 must comply with §3.14.

The Commission agrees with TXOGA regarding the definition of "casing" and adopts §3.82(b) with a change to delete that definition. The Commission finds that §3.82(c)(7) adequately specifies that wells regulated under §3.82 must comply with the requirements of §3.13 as well as the additional requirements listed in subsection (c)(7). The Commission declines to delete definitions for cementing, surface casing, and plugging because the Commission finds the proposed definitions present no conflict with the other sections in Chapter 3.

Texas Brine commented regarding the application of §3.81 and §3.82. Section 3.81 was proposed to be amended to clarify that it governs brine mining that involves injecting fluid to dissolve subsurface salt formations and then extract the salts from the resulting artificial brines. These types of wells are considered Class III Brine Mining Injection Wells. Texas Brine asked the Commission to clarify that Class III wells regulated under §3.81 are only those wells used to extract brine through the solution of a subsurface salt formation, whereas the wells governed by new rule §3.82 extract brine from naturally occurring aquifers and the reinjection of fluids, post-extraction of minerals. One area Texas Brine recommended be amended to clarify the activities regulated by §3.81 and §3.82 is the proposed definition of "brine" in §3.82(b). Texas Brine requested the definition be revised to include a statement that brine "does not include brine produced by solution of a subsurface salt formation from a brine mining injection well or Class III well as defined under §3.81." Texas Brine requested similar clarifying changes in the definitions of "brine production project" and "brine resource."

The Commission agrees with Texas Brine regarding the purpose of §3.81. The Commission proposed changes to §3.81, including amending the title, to clarify the distinction in the types of wells governed by each section. The Commission understands that certain provisions within §3.82 may still create a perceived conflict with §3.81 or otherwise cause confusion as to how the provisions relate to Class III brine mining activities. Thus, the Commission adopts §3.82(b) with changes to revise the definition of "brine resource" to exclude extraction of brine by the solution of a subsurface salt formation.

Texas Brine also requested that the Commission clarify that §§3.81 and 3.82 do not apply to injection of fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons.

The Commission agrees and adopts §3.82(a) with changes to clarify that the rule does not apply to the creation, operation, or maintenance of an underground hydrocarbon storage cavern in a salt formation regulated under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) and §3.97 of this title (relating to Underground Storage of Gas in Salt Formations).

Coghlan Crowson expressed general opposition to the framework of proposed §3.82, stating that it creates barriers for market participants using newer, more competitive technology and focuses too much on lithium to the exclusion of other minerals. Coghlan Crowson also noted future legislation or caselaw may alter the laws under which the Commission is adopting the proposed amendments and rules. Thus, Coghlan Crowson suggested the Commission only adopt the minimum requirements needed to obtain primacy from the United States Environmental Protection Agency (EPA).

The Commission understands this industry is new in Texas and is still developing. Where possible, the Commission incorporated flexibility into the requirements in new §3.82 to account for potential changes in technology or in the law. One area in which the Commission incorporated flexibility is by using the good faith claim standard for permit issuance. This standard originated in a Texas Supreme Court opinion and has been utilized by the Commission for decades. It prevents the Commission from definitively determining issues of ownership that are outside its authority and instead relies on the applicant's ability to provide a reasonably satisfactory showing of a good faith claim of ownership in the property. The Commission disagrees that §3.82 focuses too much on lithium to the exclusion of other minerals. Lithium is mentioned in §3.82 but only in a list of examples of the types of brine resources regulated under the section. The Commission used the phrase, "including, but not limited to" for the express purpose of ensuring other elements, minerals, mineral ions, salts, or other useful substances were not excluded.

Sierra Club expressed general support for proposed §3.82. Sierra Club stated the proposed rule includes reasonable notice provisions and strong facility construction and financial assurance requirements. Sierra Club requested two changes: (1) the addition of an application fee; and (2) additional required notice to groundwater conservation districts.

The Commission declines to make changes in response to Sierra Club's comments. The Commission does not currently have statutory authority to charge a brine production project application fee. The Commission disagrees that notice to groundwater conservation districts is necessary. Section 3.82(f) requires notice to local government representatives as well as notice by publication in a newspaper of general circulation. The Commission finds these forms of notice are sufficient.

TXOGA's comments contained several requests for clarification relating to the scope and purpose of §3.82. First, TXOGA asked the Commission to clarify whether any wastes generated during drilling, completions, workovers, and any spills/leaks occurring at brine production project facilities must be treated the same as wastes created at oil and gas exploration and production sites if the wastes generated at the brine facilities are characteristically the same.

The Commission agrees that wastes at a brine production project which are characteristically similar to oil and gas wastes must be handled in accordance with the Commission's waste management rules in Chapter 4 of this title, relating to Environmental Protection. Section 4.101(b) of this title (relating to Prevention of Pollution) states, "This subchapter establishes, for the purpose of protecting public health, public safety, and the environment within the scope of the Commission's statutory authority, the . . . requirements for the management of wastes associated with activities governed by the Commission including those governed under: (1) Texas Natural Resources Code Title 3, Subtitle B; (2) Texas Natural Resources Code Title 3, Subtitle D, Chapters 121-123; (3) Texas Natural Resources Code Title 5; (4) Texas Health and Safety Code Chapter 382, Subchapter K; and (5) *Texas Water Code Chapters 26, 27* *and 29*" (emphasis added). Section 4.101(c) states, "Other wastes described in subsection (b) of this section are included when this subchapter refers to oil and gas waste(s) and may be managed in accordance with the provisions of this subchapter at facilities authorized under this subchapter provided the wastes are nonhazardous and chemically and physically similar to oil and gas wastes." The Commission agrees that a reference to the waste management rules is appropriate and adopts a reference in §3.82(c)(6) to Chapter 4 of this title alongside the references to other Commission rules.

Second, TXOGA asked whether a brine production project permit allows for incidental production of oil or gas or whether separate permits are required. Similarly, TLMA suggested the Commission adopt rules to address brine produced incident to the production of oil and gas.

The Commission notes that no separate permit is required for incidental production of oil or gas at a brine production project. The Commission also notes that any oil or gas produced as an incident to brine must be reported in accordance with §3.82(i)(15). The Commission adopts changes in subsection (i)(15) to clarify that oil or gas production must be reported on the Commission Form PR, Monthly Production Report. The Commission also adopts changes in subsection (i)(15) to align the reporting timeline with the Commission's existing timeline for filing the Form PR. This change is made in response to other comments, which are discussed in more detail below. The Commission has revised the definition of "brine" to clarify that brine may include incidental amounts of naturally occurring substances such as oil and gas.

The Commission declines to make changes in response to TLMA's comment regarding the need for rules to address brine produced incident to the production of oil and gas. The Commission notes that injection of formation fluids produced in association with oil or gas production are regulated under §§3.9 and 3.46 of this title (relating to Disposal Wells, and Fluid Injection into Productive Reservoirs, respectively).

TXOGA asked the Commission to clarify the meaning of "owner" in §3.82 to specify whether the term refers to surface owners, mineral owners, or both.

The Commission understands that the proposed definition of "owner" may cause confusion because the term is used in various contexts throughout §3.82. The Commission adopts §3.82 with a change to delete the definition of owner. Any references to "owner" in the proposed version of §3.82 that are not sufficiently explained by the context in which they appear are revised upon adoption.

TXOGA suggested a change to incorporate "minerals" each time §3.82 lists "elements, salts, or other useful substances" such that the section would state "minerals, elements, salts, or other useful substances" each time that phrase appears.

Relatedly, TLMA asked that references in §3.82 to the elements and minerals to be extracted as part of a brine production project include bromine, calcium, iodine, magnesium, and potassium. Specifically, TLMA asked that the definition of "brine resource" be revised to include those additional elements.

Regarding TXOGA's comment, the Commission notes that there are two places where the phrase "elements, salts, or other useful substances" appears: (1) in §3.82(a), regarding the scope and purpose of the section; and (2) in §3.82(b)'s definition of "brine resource." Both of those places use the term "minerals" alongside elements, salts, or other useful substances." For example, the proposed definition of brine resource was, "Elements, *minerals*, salts, or other useful substances dissolved or entrained in brine, including, but not limited to, lithium, lithium ions, lithium chloride, halogens, or other halogen salts, but not including oil, gas, or any product of oil or gas" (emphasis added). The Commission makes no changes in response to TXOGA's comment.

Regarding TLMA's comment, the Commission notes that bromine and iodine are both halogens and calcium, magnesium and potassium are covered by "elements" or "minerals." The Commission makes no changes in response to this comment.

TerraVolta expressed concern regarding a potential conflict between proposed §3.82(a)(3) and the proposed amendments to §3.5. TerraVolta suggested a revision to §3.82(a)(3) to resolve this potential conflict.

The Commission agrees to incorporate a provision regarding which rule controls in the event of a conflict. If a requirement of §3.82 and another Commission rule referenced within §3.82 cannot be interpreted to allow both provisions to operate, then §3.82 controls. This standard is incorporated in subsection (a)(10).

Regarding the definition of "aquifer" in proposed §3.82(b), TLMA recommended revising the definition to remove the limitation that the formation be capable of producing a "significant amount" of water.

The Commission declines to make the recommended change because the definition of "aquifer" is consistent with how the term is defined in other Commission rules and EPA's underground injection control regulations at 40 CFR §144.3.

TLMA also asked that the definition of "area of review" be revised to expand the area of review to one-half mile from the perimeter of the brine production project rather than one-fourth mile from the perimeter of the brine production project. TLMA stated this change would ensure consistency with §3.82(d) and would recognize the "highly fugacious" nature of water.

The Commission declines to make the recommended change. Unless special field rules provide different spacing requirements or the applicant obtains an exception, Section 3.82(d)(1) requires that all brine production wells and Class V spent brine return injection wells be completed (1) within the brine production project area; (2) no less than one-half mile from the boundary of the brine production project area; and (3) no less than one-half mile from any interest within the brine production project area that is not participating in the project. In a brine production project, brine is both extracted from and re-injected into the same formation such that the reservoir pressure is relatively balanced within the brine production project area. The Commission notes clarifying changes are adopted in the definition of "area of review" in response to other comments described below.

Regarding the proposed definition of "brine production project," TLMA asked for revisions to include in the definition "facilities utilized for the direct extraction of elements and minerals from the brine."

The Commission declines to make this change because the proposed definition of "brine production project" already includes any equipment associated with the project. Equipment includes facilities utilized for the direct extraction of elements and minerals from the brine.

Texas Brine asked the Commission to clarify whether the reference to "gas" in the proposed definition of "brine resource" refers to oil and gas production or naturally occurring gas that may be associated with brine deposits.

The Commission notes that in response to another comment detailed below, the Commission agreed to adopt the definition of brine with changes to indicate that "naturally-occurring substances" may include entrained oil or gas, including hydrogen sulfide gas.

TLMA recommended the proposed definition of "good faith claim" be revised to include "such as evidence of a currently valid brine extraction lease or a recorded deed conveying a fee interest in an estate that includes brine resources" so that the definition is consistent with the definition of "good faith claim" in §3.15 of this title, relating to Surface Equipment Removal Requirements and Inactive Wells.

The Commission disagrees that the types of documents evidencing a good faith claim need to be included in the definition. The proposed definition is similar to the definition of good faith claim in the Commission's rules related to Class VI facilities in Chapter 5 of this title, relating to Carbon Dioxide (CO_2).

TXOGA commented that the definition of "spent brine" should be expanded to include all entrained gases and chemicals in the injection fluid including but not limited to hydrogen sulfide (H_2S). TXOGA stated this will ensure all contents of the produced brine present in the formation under natural conditions will be authorized for reinjection under the Class V UIC program. TXOGA also requested the

Commission recognize that spent brine may contain other non-hazardous substances used in production and processing (e.g., acid base and hydrogen peroxide).

The Commission adopts changes to the definition of brine in §3.82(b) to clarify that brine may include entrained oil or gas. The Commission declines to adopt changes to the definition of spent brine because the proposed definition already contemplates additives used in processing.

Additionally, TXOGA requested the Commission add definitions of "facility" and "unleased lands." TXOGA proposed the following definition of facility: "the brine production well, the Class V spent brine return injection well, and any other discrete or identifiable structure or enclosure used in conjunction with such wells that constitutes or contains a stationary source. Stationary sources lasting less than 72 hours are not considered facilities." TXOGA did not provide a proposed definition of "unleased lands" but stated the definition was needed to clarify if requirements for unleased lands would apply to unleased surface, mineral, or both.

The Commission declines to include a definition for "facility" because the definition of "brine production project" is "a project the purpose of which is the extraction of brine resources from a brine field. The term includes brine production wells, Class V spent brine return injection wells, monitoring wells, brine flowlines, and any equipment associated with the project." However, the term "facility" is used in §3.82 in several places and the Commission has replaced "facility" with "brine production project." The Commission also notes that the term "stationary source" is a term used almost exclusively in regulations for air emissions, for which the Commission has no jurisdiction.

The Commission also declines to add a definition for "unleased lands" because the term is not used in §3.82.

Proposed §3.82(c) contained the general requirements for a brine production project. The Commission received comments from Coghlan Crowson, Texas Brine, TLMA, and TXOGA related to the proposed requirements in subsection (c).

TXOGA asked the Commission to allow reinjection of the spent brine into a different formation than the formation from which the brine was produced.

The Commission declines to make the requested change. Texas Water Code §27.036, which gives the Commission authority to adopt these requirements, and the relevant EPA regulations require Class V brine injection wells to reinject spent brine into the same formation from which the brine was produced.

Coghlan Crowson asked the Commission to reconsider whether reinjection must take place within the boundary of the brine production project. Coghlan stated there may be potential for Class V injection wells to be centralized with operators accepting spent brine for injection into the same formation from which they were produced but not on the same tract as the project.

The Commission declines to allow reinjection to occur offsite. The Commission notes that the spent brine is required to be reinjected into the same formation from which the brine was produced. Allowing third party disposal companies to accept and dispose of the spent brine would hinder the Commission's ability to enforce the requirements of Water Code §27.036 and related federal requirements for Class V injection wells. Offsite disposal may also create waste and impact correlative rights. The Commission has improved oversight of these areas when reinjection of spent brine occurs onsite.

TXOGA asked whether a brine production project must comply with §3.36 of this title if the spent brine contains hydrogen sulfide gas (H2S).

The Commission notes that §3.82(c)(6)(I) requires the operator of a brine production project to comply with §3.36 of this title. The Commission made no change in response to this comment.

Regarding the financial security requirements proposed in §3.82(c), Texas Brine asked the Commission to explain why financial security is required for each well rather than for all wells and equipment used as part of the brine production project.

TXOGA also commented regarding financial security requirements. TXOGA asked the Commission to allow blanket bonds similar to other financial security requirements for operations within the Commission's jurisdiction.

The Commission agrees with these comments and adopts §3.82(i)(8) to clarify that both individual and blanket performance bonds are an acceptable form of financial assurance.

TLMA commented regarding the provision proposed in §3.82(c)(9) that allows for a refund of a portion of a cash deposit filed as financial security once a well is plugged. TLMA suggested allowing a refund only in the event the Commission has financial security from the operator sufficient to plug all remaining wells in brine production projects operated by the operator, not just the wells in the brine production project in which the plugged well exists.

The Commission declines to make the requested change because the Commission has an existing process for modifying an operator's financial assurance based on the number of wells operated and chooses to follow that process to ensure consistency. The Commission notes that the refund provision only applies when an operator has submitted a cash deposit to meet financial assurance requirements, which the Commission anticipates will be infrequent.

Regarding §3.82(d)(2) and proposed requirements related to spacing, acreage, density and field rules, Coghlan Crowson commented that the proposed minimum unit size of 1,280 acres is overly large and prohibitive. It will effectively box out smaller acreage blocks from being developed. Coghlan recommended the Commission use a zone of influence calculation to determine acreage assignment instead. This approach would allow for flexibility as technology is developed.

The Commission disagrees that the proposed minimum acreage amount is overly large. A distinguishing feature of Class V brine mining is the need to return spent brine to the formation from which it was produced after extraction of the resource being mined. Returning spent brine to the zone from which it was produced is intended to maintain formation pressure and thereby prevent waste. However, this also means every injection well creates a zone around it that is dominated by spent brine – brine which no longer contains the resource being mined. Thus, the correlative rights of the owners of the land where the injection wells are located may be impacted if the owners do not share in the benefits of the brine mining. The Commission incorporated a solution to this potential correlative rights problem by requiring all injection wells to be located in the same project as the production wells they serve. This means projects may require more land than would be common in the oil and gas context.

Regarding Coghlan's concern about preventing the development of smaller acreage blocks, the Commission proposed two types of exception processes to ensure flexibility for different types of operators and operations. An operator with a project that cannot meet the minimum acreage requirement (or cannot meet the spacing or contiguity requirements) may apply for an exception to the requirement for that specific project. This process is outlined in §3.82(d)(4). In addition, an operator may seek special field rules that provide alternate spacing, density, or contiguity requirements for all brine production projects in a field. That process is outlined in §3.82(d)(3)(B) and (d)(3)(C). As discussed below in response to the comments submitted on proposed §3.82(d), the Commission adopts changes in subsection (d) to allow administrative approval of exceptions when no protest to the exception is submitted. Thus, operators seeking an exception will not be required to go through a hearing process for each exception.

TXOGA commented requesting clarification on the proposed 1,280-acre minimum. TXOGA asked whether the acreage amount relates to mineral or surface acreage. TXOGA's comments also contained several questions regarding ownership and leasing.

The Commission notes that the required minimum acreage is based on surface acreage. However, the Commission also notes that a good faith claim to produce the brine resources is required for each tract that is included in the brine production project. The Commission declines to answer TXOGA's questions regarding ownership and leasing. The Commission's practice is to ensure an operator submitting an application to produce minerals under the Commission's jurisdiction has a good faith claim to produce those minerals. Therefore, under §3.82, a good faith claim as defined in §3.82(b) is required to include a tract in a brine production project.

Regarding proposed §3.82(d)(2) and provisions relating to assignment of acreage, Standard Lithium and TXOGA stated that they support that subsection (d)(2) makes assignment of acreage optional but asked that the Commission add language to ensure the same acreage is not utilized by multiple operators. They asked the Commission to require that once acreage is assigned to a well in one project, it must be drawn out of all overlapping projects.

TLMA recommended this issue be resolved by changing subsection (d)(2) to require assignment of acreage rather than making it optional. TLMA stated mandatory assignment will help the Commission achieve the goals in proposed §3.82(d)(2)(C) and (d)(2)(D).

The Commission agrees with TLMA and adopts subsection (d)(2) with changes to require assignment of acreage. This is necessary to ensure enforcement of the prohibition against multiple assignment of the same acreage.

Proposed §3.82(d)(2) also included a maximum diagonal requirement, which states that the two farthermost points of acreage assigned to a project shall not exceed 23,760 feet. Texas Brine asked the Commission to clarify the meaning of this requirement.

The Commission notes that subsection (d)(2)(D) requires that the two farthermost points of acreage assigned to the well not exceed 23,760 feet, and the acreage assigned include all productive portions of the wellbore. This maximum diagonal provision is intended to prevent acreage designation resulting in an irregular shape. The diagonal of 23,760 feet assumes the maximum 5,120 acres has been assigned to the well, creating an acreage assignment in the shape of a rectangle that is two miles wide and four miles long. For this acreage designation, 23,760 feet is the farthest diagonal between two points on opposite sides of the rectangle. Special field rules may alter the maximum diagonal.

Coghlan Crowson commented that the requirement proposed in §3.82(d)(3) relating to notice for a new brine field designation is too broad such that it will discourage competition and lead to unnecessary arguments amongst operators.

The Commission agrees with this comment and adopts a two- and one-half-mile distance consistent with the distance in §3.41 of this title (relating to Application for New Oil or Gas Field Designation and/or Allowable) and §3.43 of this title (relating to Application for Temporary Field Rules).

Texas Brine commented that the provisions in §3.82 relating to brine field designation may create confusion due to existing Class III brine mining operations. Texas Brine asked for a new definition of "brine field" to clarify that it does not apply to subsurface salt formations that are solution mined under §3.81.

The Commission notes that its revisions to the definition of "brine resource" adopted in §3.82(b) in response to Texas Brine's comments make clear that "brine field" as used in §3.82 does not relate to formations that are solution mined under §3.81. The revised definition of "brine resource" clarifies that the term does not include brine extracted after injecting fluid to dissolve subsurface salt formations. The Commission declines to make additional changes in response to this comment.

Standard Lithium, TerraVolta, and TXOGA expressed opposition to the requirement proposed in §3.82(d)(3), which would require a hearing to designate each new brine field. The commenters asked that the Commission allow new brine fields to be designated administratively.

The Commission disagrees. The Commission recognizes that new fields are designated administratively in the oil and gas context. However, because this industry and regulatory scheme are new and untested, the Commission considers it prudent to require new brine fields to be designated through a hearing instead. Once a brine field is established, further hearings would not be required unless an operator requests special field rules or a project-specific exception to the rules in §3.82.

Coghlan Crowson requested that operators be allowed a buffer of time before being required to submit electric logs for brine field designation. Coghlan noted that these logs are proprietary.

The Commission declines to include a buffer of time before the operator is required to submit electric logs. The Commission finds that logs are necessary for the Commission to determine whether a new brine field designation is warranted. However, the Commission understands that this information is considered proprietary. Thus, the Commission adopts §3.82(d)(3)(A)(iii) with changes to allow logs to be marked confidential. Logs marked confidential will be treated consistently with any information in the Commission's possession that is marked confidential by a filer – if the information is requested through the Texas Public Information Act, the Commission will notify the filer of the request and provide instructions for the filer to seek a ruling from the Office of the Attorney General regarding whether the Commission is required to release the information, or whether the information may be withheld as confidential. Language regarding this process is adopted in §3.82(d)(3)(A)(iii).

Coghlan Crowson also commented regarding §3.82's provision allowing an application for special field rules. Coghlan expressed opposition to having rules relating to brine production projects in two places (i.e., in statewide rules included in §3.82 and in special field rules).

The Commission declines to remove the provision allowing application for special field rules. As mentioned in response to Coghlan's comments above, the Commission finds special field rules and the exceptions process provide flexibility for developments in technology and the brine mining industry as a whole.

Regarding the proposed requirements related to obtaining exceptions to the density and spacing requirements, Standard Lithium, TerraVolta, and TXOGA requested that the Commission remove the requirement to hold a hearing on every request for exception. Instead, the commenters suggest a process similar to exceptions in the oil and gas context, which only requires a hearing if the Commission receives a protest to the exception application.

The Commission agrees that a hearing should not be required unless a protest is submitted and adopts §3.82(d)(4) with changes accordingly.

Coghlan Crowson expressed opposition to the requirement proposed in §3.82(e)(3)(M), which requires the applicant to provide a corrective action plan for any known wells in the area of review that penetrate the brine field and that may allow fluid migration into underground sources of drinking water (USDWs) from the brine field for which the applicant cannot demonstrate proper completion, plugging, or abandonment. Coghlan stated that the brine project operator should not be required to determine whether existing abandoned wells were properly plugged and abandoned.

The Commission declines to make the recommended change. The federal underground injection control regulations require corrective action on any well within the area of review to protect USDWs.

Standard Lithium, TerraVolta, and TXOGA requested changes to §3.82(e)(3)(N) to remove the requirement to determine all of the owners within the area of review, which is an extra quarter mile beyond the project boundaries. The commenters noted the title examination needed to meet this requirement is burdensome and carries a significant cost. The commenters recommended that references to the area of review in §3.82(e)(3)(N) be replaced with "within the brine field." For the same reason, the commenters requested similar changes to the notice requirements proposed in §3.82(f).

The Commission agrees and adopts the definition of "area of review," §3.82(e)(3)(N), and §3.82(f) with changes accordingly. The changes to the definition of area of review reflect that due to the spacing requirement that prohibits wells within one-half mile from the project boundary, the area of review does not extend beyond the brine production project area unless an exception results in an injection well location closer than one-half mile to the boundary of the brine production project area. If an such an exception is granted, then the area of review is a one-half mile radius around the injection well location. Corresponding changes are adopted in §3.82(e)(3)(N), §3.82(e)(4)(B), and §3.82(f).

Texas Brine expressed opposition to proposed §3.82(e)(3)(T), which provides the Director with discretion to request any other information reasonably required prior to issuing the permit. Texas Brine stated this discretion leads to uncertainty and asked the Commission to put operators on notice of what the Commission will request in the application.

The Commission declines to make changes in response to this comment. Several comments have noted the need to maintain flexibility to allow the industry and different forms of technology associated with brine production projects to develop. The Commission supports giving operators flexibility but also needs to retain the ability to request additional information for a specific project when warranted.

Coghlan Crowson and TXOGA expressed support for §3.82(g), which contains a 30-day review deadline by which the Director will notify the applicant whether the application is complete or deficient. Coghlan recommended the Commission also include a deadline for final approval, such as 180 days.

The Commission declines to include a deadline for final approval. The Commission reserves flexibility in the time needed to review brine production project applications because brine extraction is a new industry in Texas and because many of these projects will be quite large.

Regarding proposed §3.82(h), Standard Lithium noted a potential typographical error in subsection (h)(2)(D), which states "specific data" rather than "specific date."

The Commission agrees this is the intent and adopts §3.82(h) with the suggested correction.

Standard Lithium commented that fire walls are unnecessary in brine production projects unless hydrocarbons are being stored onsite. Standard Lithium suggested the Commission restrict the language in §3.82(i) to dikes in the absence of flammable materials.

The Commission partially agrees with this comment. The Commission believes that the erection of dikes or berms around vessels holding fluids is prudent. The Commission has replaced the term "fire walls" with the term "berms."

Regarding the reporting and records retention requirements proposed in §3.82(i), TXOGA recommended changing the production reporting requirement to on or before the last day of the month following the month covered by the report. This would be consistent with production reporting in the oil and gas context.

The Commission agrees and adopts §3.82(i)(15)(C) with the requested change.

TLMA asked that the Commission extend the required minimum record retention period from 5 to 7 years because the industry is in its infancy in Texas.

The Commission agrees that the records should be kept longer than five years from the date of commencement of brine production and has revised the language in subsection (i)(15)(B) to require that the permittee retain records of all information required by the permit for at least five years from the date brine production ceases.

Coghlan Crowson and Texas Brine commented regarding well plugging requirements proposed in §3.82(i)(16). Coghlan asked if full field removal and restoration is required to be completed within one year of ceasing production. If so, Coghlan said this requirement is not practical because it takes years to properly plan for full field removal.

Texas Brine asked that the Commission include a provision allowing operators to request a plugging extension.

The Commission declines to make changes in response to these comments. Section 3.82(i)(16) already allows the Director, for good cause, to grant a reasonable extension of time in which to plug the wells if the operator submits a proposal that describes actions or procedures to ensure that the wells will not endanger USDWs during the period of the extension.

TXOGA made several suggestions relating to the operating requirements for injection wells proposed in §3.82(j)(4). First, TXOGA noted that setting of surface casing is based on the base of useable quality water but §3.82's definition of USDW appears to impact that practice. TXOGA asked for clarification regarding whether the determination of USDW will be used to require deeper setting of surface casing.

The Commission notes that the definition of USDW does not impact the requirement in §3.82(j)(4)(B)(ii), which requires that the operator set and cement surface casing from at least 100 feet below the lowermost base of usable quality water as defined by the Geologic Advisory Unit to the surface, regardless of the total depth of the well.

Next, TXOGA noted that in deeper formations, circulation of cement to surface may not be technically feasible and suggested that the Commission allow an alternate surface casing program for good cause in accordance with §3.13.

The Commission notes that §3.82(j)(4)(B)(iii) requires that the operator of a Class V spent brine injection well set and cement long string casing at a minimum from the top of the brine field to the surface unless the Director approves an alternate completion for good cause. Thus, if circulation of cement to the surface is not technically feasible, the Director may approve an alternate casing program. The Commission made no change in response to this comment.

Further, regarding proposed §3.82(j)(4)(C), TXOGA commented that there is often uncertainty around reaching casing depth and getting service crews to a well location. Thus, TXOGA recommended a shorter notice period such as 48 hours.

The Commission agrees with this comment and has revised the language of §3.82(j)(4)(C) to change the notice from 15 days to 48 hours.

Regarding the requirement for mechanical integrity tests proposed in §3.82(j)(7)(J), Standard Lithium asked the Commission to modify the language to allow the 15-day deadline to begin when the test results are received.

The Commission declines to make the recommended change because it finds that the language in §3.82(j)(7)(J) achieves the same result as Standard Lithium's recommended language. Section 3.82(j)(7)(J)'s 15-day deadline begins upon the well's failure to demonstrate mechanical integrity and the failure will not be known to the operator until the operator receives test results. However, the Commission adopts §3.82(j)(7)(H) and (j)(7)(J) with changes to clarify the requirements.

TXOGA commented regarding proposed requirements in §3.82(j)(4)(G). TXOGA stated that the prohibition on beginning injection operations until the completion report is submitted and approved may cause too much delay. TXOGA suggested allowing operations to begin once the report is submitted unless otherwise instructed by the Director. Alternatively, TXOGA asked that the Commission establish a deadline for the Commission's review of the completion report, such as 30-45 days.

The Commission agrees with this comment and adopts §3.82(j)(4)(G) to state that if the permittee has not received notice from the Director that the well is in compliance with this section and the permit within 45 days of submission of the completion report, the permittee may begin injection operations.

Regarding annulus pressure maintenance requirements proposed in §3.82(j)(5)(D), TXOGA asked the Commission to allow monitoring of all pressures using Supervisory Control and Data Acquisition (SCADA) systems and include a corresponding reporting requirement. TXOGA suggested the following language: The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

The Commission agrees that a pressure change could be the result of impacts from changes in temperature and adopts §3.82(j)(5)(D) with changes accordingly. The Commission also makes corresponding changes in subsection (j)(5)(D) and (j)(7)(K) to remove language relating to movement of fluid through channels adjacent to the wellbore as this language is unsuitable in provisions addressing both internal and external mechanical integrity.

This concludes the summary of comments received on the proposal. The remaining paragraphs summarize the adopted rules.

The amendments adopted in §§3.1, 3.5, 3.7, 3.12, 3.13, 3.16, 3.17, 3.32, 3.36, and 3.73 add references to brine resources and spent brine return injection wells as applicable or otherwise clarify requirements of those sections related to brine production and injection. The amendments in §§3.1 and 3.36 also add references to geothermal resources. The amendments in §3.78 add references to encompass brine resources and revise outdated language related to National Pollutant Elimination System (NPDES) permits and processing of checks.

The Commission adopts amendments to §3.81 to revise the title to Class III Brine Mining Injection Wells. The amendments also clarify the definition of brine mining injection well for purposes of §3.81. That section addresses requirements for Class III injection wells used to inject fluid to dissolve subsurface salt formations and then extract the salts from the resulting artificial brines. SB 1186 did not impact the Commission's existing authority over Class III brine mining injection wells or any existing permits for such operations. The amendments to the title will clarify that the requirements of §3.81 do not apply to brine production projects and associated injection wells, which are addressed in new §3.82. As mentioned above, several provisions in §3.82 are adopted with changes to further clarify the scope and operation of §3.81 and §3.82.

Adopted §3.82(a) describes the scope and purpose of the new rule. The new rule contains regulations for brine production projects and the associated brine production wells for the extraction of elements, minerals, mineral ions, salts, or other useful substances, including, but not limited to, lithium, lithium ions, lithium chloride, halogens or halogen salts, from a subsurface formation but not including oil, gas, or any product of oil or gas, or fluid oil and gas waste. "Product of oil and gas" is defined by Natural Resources Code §85.001 and "fluid oil and gas waste" is defined by Natural Resources Code §122.001. Subsection (a) also states that the section governs Class V spent brine return injection wells used in association with brine production projects for the reinjection of the spent brine. Subsection (a)(2) - (5) contains other clarifications related to the scope of §3.82. As described above, the Commission added subsection (a)(6) in response to comments to clarify that §3.82 does not apply to the creation, operation, or maintenance of an underground hydrocarbon storage cavern in a salt formation regulated under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) and §3.97 of this title (relating to Underground Storage of Gas in Salt Formations). The Commission also adopts the section with a change to add subsection (a)(10), which addresses any conflict between §3.82 and requirements of other Commission rules referenced within §3.82.

Section 3.82(b) contains the definitions for terms used within §3.82. As noted above, the following definitions are changed in the adopted version of subsection (b): area of review, brine, brine resource, and Commission. The Commission also did not adopt proposed definitions of casing and owner.

The Commission adopts general requirements for brine production projects in §3.82(c). Brine production projects are required to be permitted in accordance with §3.82 before a person may construct or operate brine production wells or Class V spent brine return injection wells. Subsection (c)(2) specifies the persons authorized to sign applications and reports related to the brine production project. Subsection (c)(2)(A) - (C) contains requirements identical to those in §3.81 for Class III brine mining injection wells.

Subsection (c)(3) requires operators of all Class V spent brine return injection wells to re-inject spent brine into the brine field from which the brine was produced. In subsection (c)(4), the Commission requires all brine production wells and Class V spent brine return injection wells be drilled and completed or recompleted, operated, maintained, and plugged in accordance with the requirements of §3.82 and the brine production project permit.

Subsection (c)(5) instructs the Commission to assign a lease number to the brine production project and requires that lease number to be used by the project operator on required forms and reports.

In §3.82(c)(6) – (9), the Commission lists the other rules with which a brine production project shall comply. Subsection (c)(7) – (9) states that an applicant for a brine production project shall comply with §§3.13, 3.14, 3.15, 3.35, and 3.78, but the applicant shall also comply with additional requirements specifically applicable to brine production projects.

Subsection (d) contains statewide field rules for spacing, acreage, and density of brine production projects. The subsection also addresses the process for requesting an exception to the statewide rules or adopting field rules for a particular brine field. As discussed above, the Commission adopts subsection (d) with several changes based on the comments.

Subsection (e) contains the application requirements for a brine production project permit. Applications for a brine production project permit shall be submitted to the Director in compliance with subsection (e). A brine production project permit application is similar to an application for an area permit, which is addressed in §3.46(k) of this title, relating to Fluid Injection into Productive Reservoirs. The applicant for a brine production project permit is not required to submit applications for individual production and injection well permits at the same time the applicant files the brine production project permit application. Rather, the applicant is required to submit the information required by subsection (e)(3) and shall also submit an application for at least one injection well. The requirements for obtaining a Class V spent brine return injection well permit are adopted in §3.82(e)(4).

Subsection (e)(3) specifies the required contents of a brine production project permit application. Subsection (e)(3) also contains requirements for the permit application to include the proposed operating data; a letter from the Geologic Advisory Unit of the Oil and Gas Division of the Railroad Commission of Texas stating that the use of the brine field for the injection of spent brine will not endanger usable quality water or USDWs; and an accurate plat showing the entire extent of the area of review. Subsection (e)(3)(M) contains the elements required to be included on the plat.

In §3.82(e)(3)(N), the Commission requires the applicant for a brine production project to provide an additional plat showing the outline of the brine production project area and other specified elements. As noted above, the Commission adopts changes to subsection (e)(3)(N) based on the comments.

Additional contents required to be included in the permit are adopted in §3.82(e)(3)(O) through (e)(3)(T). Several of the provisions are modeled after existing Commission requirements for injection well permit applications.

In §3.82(e)(4), the Commission adopts requirements for Class V spent brine return injection well permits. An operator of a Class V spent brine return injection well shall file an application for an individual well permit prior to commencement of injection operations into any Class V spent brine return injection well within the brine production project area. The required contents of the application are in §3.82(e)(4)(A) through (e)(4)(F).

In §3.82(e)(5), the Commission includes criteria for exempted aquifers, and in subsection (e)(6), the Commission requires all Class V spent brine return injection wells covered by a brine production project permit to be completed, operated, maintained, and plugged in accordance with the requirements of subsection (j) and the brine production project permit. Regarding exempted aquifers, the Commission adopts 40 CFR §144.7 and §146.4 by reference effective February 19, 2025, which is the effective date for the new rule and amendments.

Subsection (f) contains the notice requirements for a brine production project, including the requirement to identify whether any portion of the area of review (AOR) encompasses an Environmental Justice (EJ) or Limited English-Speaking Household community using the most recent U.S. Census Bureau American Community Survey data. If the AOR includes an EJ or Limited English-Speaking Household community, the applicant shall conduct enhanced public outreach activities to these communities, including a public meeting. Other efforts to include EJ and Limited English-Speaking Household communities are required in subsection (f)(1)(A) - (E).

An applicant for a brine production project permit is required to provide notice of its application to the persons identified in subsection (f)(2). As noted above, the Commission adopts subsection (f) with changes due to comments.

Subsection (f)(2)(B) requires the applicant to mail or deliver notice in a form approved by the Commission. Notice shall be provided after Commission staff determines the application is complete. In addition, the applicant is required to publish notice of the brine production project permit application in a form approved by the Commission in a newspaper of general circulation.

Subsection (f)(2)(C) specifies the information that the applicant must include in the notice.

Subsection (f)(2)(D) and (E) clarify the notice requirements for individual Class V spent brine return injection wells and brine production wells. Once an applicant complies with the notice required to obtain a brine production project permit and the permit has been issued, no notice shall be required when filing an application for an individual injection well permit for any Class V spent brine return injection well or brine production well covered by the brine production permit unless otherwise provided in the permit or unless the applicant requests an exception.

Subsection (f)(3) specifies that an affected person has 30 days to file a protest and an interested person has 30 days to submit written comments on the brine production project permit application.

Subsection (f)(4) outlines when the Commission will hold a hearing on the brine production project permit application.

In §3.82(g), the Commission outlines the process for review of brine production project permit applications, including procedures for determining whether the application is complete and notifying the applicant of any deficiencies in the application.

Subsection (g)(2) addresses amendments to a permit. If a permittee seeks to make changes to brine production project and the changes are substantial, such as changing the exterior boundaries of, or maximum number of wells authorized in, the brine production project area, then the changes cannot be made unless the permittee files an application to amend the permit. An application to amend is also required if the permittee seeks to alter permit conditions.

Subsection (h) addresses procedures for Commission action on a permit including modification, revocation and reissuance, and termination.

Subsection (i) contains the standard permit conditions that will be included in a brine production project permit. In §3.82(i)(1), the Commission requires a brine production project permittee to provide access to the project facilities and records to Commission staff members. Similarly, §3.82(i)(2) states the Commission may make any tests on any well at any time necessary for regulation of wells under this section, and the operator of such wells shall comply with any directives of the Commission to make such tests in a proper manner.

Subsections (i)(3) - (19) contain additional permit conditions on topics including maintenance of financial assurance; the permit term and requirement for the permit to be reviewed once every five years; permit transfers, renewals, and other actions; monitoring, records, and reporting; plugging; identification; and dikes and berms. Subsections (i)(8), (i)(15), and (i)(18) are revised upon adoption in response to comments.

Subsection (j) contains additional standard permit conditions for Class V spent brine return injection wells. The permit conditions in subsection (j) apply in addition to the conditions imposed in subsection (i).

Subsection (j)(4) specifies drilling and construction requirements for Class V spent brine return injection wells. Section 3.82(j)(4)(C) and (j)(4)(G) are adopted with changes based on the comments.

Subsection (j)(5) contains the minimum permit conditions relating to how the Class V spent brine return injection well must be operated. Importantly, all Class V spent brine return injection shall be into the same brine field from which the brine was extracted by the brine production wells. Subsection (j)(5)(D) is adopted with changes due to comments.

The permit condition in subsection (j)(6) specifies that, if necessary to prevent movement of fluid into USDWs, corrective action will be required for all known wells in the area of review that penetrate the top of the brine field for which the operator cannot demonstrate proper completion, plugging, or abandonment.

Section 3.82(j)(7) addresses requirements for mechanical integrity. A Class V spent brine return injection well may not be used if it lacks mechanical integrity. Subsection (j)(7) is adopted with changes based on comments.

In §3.82(j)(8) the Commission adopts permit conditions for Class V spent brine return injection wells relating to required monitoring, record-keeping, and reporting. Subsection (j)(8) contains requirements for how long monitoring information shall be retained, the contents of the monitoring records, and reports that shall be made to the Commission, including reports of noncompliance that may endanger USDWs, human health, or the environment. Subsection (j)(9) requires the permittee to provide the Commission notice 48 hours before performing any workover or corrective maintenance operations that involve the unseating of the packer or well stimulation. Subsection (j)(10) specifies that the Commission may establish additional permit conditions for Class V spent brine return injection wells on a case-by-case basis.

Subsection (k) describes the consequences for violations of §3.82. Any well drilled or operated in violation of §3.82 without a permit shall be plugged. In addition, violations of the requirements of §3.82 may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3. A brine production well in violation of §3.82 may have its certificate of compliance revoked in the manner provided in §3.73(d) - (g), (i) - (k) of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance).

Subsection (l) clarifies that administrative actions taken pursuant to the provisions of §3.82 are subject to review by the commissioners. Subsection (m) clarifies references to the Code of Federal Regulations (CFR) within §3.82 and states where the federal regulations are available for review.

Finally, in §3.82(n) the Commission clarifies the effective date for the section. The Commission will seek primacy from the United States Environmental Protection Agency so that the Commission may administer the Class V UIC program for spent brine return injection wells. The regulations in §3.82 pertaining to Class V spent brine return injection wells become effective upon EPA approval of the Commission's program. Until then, an operator of a brine production project must obtain a permit from the EPA to operate a Class V spent brine return injection well. All other regulations proposed in §3.82 become effective as provided in the Administrative Procedure Act (APA), in Section 2001.001 et seq. of the Texas Government Code. The effective date based on the APA is February 19, 2025.

The Commission adopts the new rule and amendments pursuant to Senate Bill 1186 and Texas Water Code §27.036, which provide the Commission jurisdiction over brine mining and authorize the Commission to issue permits for brine production wells and injection wells used for brine mining, and also instruct the Commission to adopt rules necessary to administer and regulate brine mining; Texas Natural Resources Code §§81.051 and 81.052, which provide the Commission with 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 102, which gives the Commission the authority to establish pooled units for the purpose of avoiding the drilling of unnecessary wells, protecting correlative rights, or preventing waste; and Texas Natural Resources Code §§85.201 - 85.202, which require the Commission to adopt and enforce rules and orders for the conservation and prevention of waste of oil and gas, and specifically for drilling of wells.

Statutory authority: Texas Natural Resources Code §§81.051, 81.052, 85.201, 85.202 and Chapter 102; Texas Water Code §27.036.

Cross reference to statute: Texas Natural Resources Code Chapters 81, 85, and 102; Water Code Chapter 27.

§3.1. Organization Report; Retention of Records; Notice Requirements.

(a) Filing requirements.

(1) Except as provided under subsection (e) of this section, no organization, including any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission shall perform such operations without having on file with the Commission an approved organization report and financial security as required by Texas Natural Resources Code §§91.103 - 91.1091. Operations within the jurisdiction of the Commission include, but are not limited to, the following:

(A) drilling, operating, or producing any oil, gas, brine, geothermal resource, spent brine return injection, brine mining injection, fluid injection, or oil and gas waste disposal well;

(B) transporting, reclaiming, treating, processing, or refining crude oil, gas and products, brine resources, or geothermal resources and associated minerals;

(C) - (K) (No change.)

(2) - (10) (No change.)

(b) Record requirements. All entities who perform operations which are within the jurisdiction of the Commission shall keep books showing accurate records of the drilling, redrilling, or deepening of wells, the volumes of crude oil on hand at the end of each month, the volumes of oil, gas, brine, and geothermal resources produced and disposed of, together with records of such information on leases or property sold or transferred, and other information as required by Commission rules and regulations in connection with the performance of such operations, which books shall be kept open for the inspection of the Commission or its representatives, and shall report such information as required by the Commission to do so.

(c) - (d) (No change.)

(e) Issuance of permits to organizations without active organization reports.

(1) Notwithstanding contrary provisions of this section, the Commission or its delegate may issue a permit to an organization or individual that does not have an active organization report or does not ordinarily conduct [~~oil and gas~~] activities under the jurisdiction of the Commission when the issuance of such a permit is determined to be necessary to implement a compliance schedule, or to remedy circumstances or a violation of a Commission rule, order, license, permit, or certificate of compliance relating to safety or the prevention of pollution. For permits issued under this subsection, the Commission or its delegate may impose special conditions or terms not found in like permits issued pursuant to other Commission rules. Any organization or individual who requests such a permit shall file an organization report and any other required forms for record-keeping purposes only. The report or form shall contain all information ordinarily required to be submitted to the Commission or its delegate.

(2) This section shall not limit the Commission's authority to plug or to replug wells or to clean up pollution or unpermitted discharges of [~~oil and gas~~] waste under the jurisdiction of the Commission.

(f) - (g) (No change.)

(h) Pursuant to Texas Natural Resources Code, §91.706(b), if an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been canceled, the Commission or its delegate may refuse to renew the operator's organization report required by Texas Natural Resources Code, §91.142, until the operator pays the fee required by §3.78(b)(8) [~~§3.78(b)(9)~~] of this title (relating to Fees and Financial Security Requirements) and the Commission or its delegate issues the certificate of compliance required for that well.

§3.5. Application To Drill, Deepen, Reenter, or Plug Back.

(a) Requirements for spacing, density, and units. An application for a permit to drill, deepen, plug back, or reenter any oil well, gas well, brine production well, or geothermal resource well shall be made under the provisions of §§3.37, 3.38, 3.39, [~~and/or~~] 3.40, and/or 3.82 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; [~~and~~] Assignment of Acreage to Pooled Development and Proration Units; and Brine Production Projects and Associated Brine Production Wells and Class V Spent Brine Return Injection Wells) (Statewide Rules 37, 38, 39, [~~and~~] 40, and 82), or as an exception thereto, or under special rules governing any particular oil, gas, brine, or geothermal resource field or as an exception thereto and filed with the commission on a form approved by the commission. An application must be accompanied by any relevant information, form, or certification required by the Railroad Commission or a commission representative necessary to determine compliance with this rule and state law.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Application--Request by an organization made either on the prescribed form or electronically pursuant to procedures for electronic filings adopted by the commission for a permit to drill, deepen, plug back, or reenter any oil well, gas well, brine production well, or geothermal resource well.

(2) - (3) (No change.)

(c) - (d) (No change.)

(e) Exploratory and specialty wells. An application for any exploratory well or cathodic protection well that penetrates the base of the fresh water strata, fluid injection well, injection water source well, disposal well, brine production well, brine solution mining well, spent brine return injection well, or underground hydrocarbon storage well shall be made and filed with the commission on a form approved by the commission. Operations for drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission. For an exploratory well, an exception to filing such form prior to commencing operations may be obtained if an application for a core hole test is filed with the commission.

(f) - (h) (No change.)

§3.7. Strata To Be Sealed Off.

Whenever hydrocarbon, brine or geothermal resource fluids are encountered in any well drilled for oil, gas, brine, or geothermal resources in this state, such fluid shall be confined in its original stratum until it can be produced and utilized without waste. Each such stratum shall be adequately protected from infiltrating waters. Wells may be drilled deeper after encountering a stratum bearing such fluids if such drilling shall be prosecuted with diligence and any such fluids be confined in its stratum and protected as aforesaid upon completion of the well. The commission will require each such stratum to be cased off and protected, if in its discretion it shall be reasonably necessary and proper to do so.

§3.12. Directional Survey Company Report.

(a) For each well drilled for oil, gas, <u>brine,</u> or geothermal resources for which a directional survey report is required by rule, regulation, or order, the surveying company shall prepare and file the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(1) - (7) (No change.)

(b) (No change.)

§3.13. Casing, Cementing, Drilling, Well Control, and Completion Requirements.

(a) General. Operators shall comply with this section for any wells that will be spudded on or after January 1, 2014.

(1) (No change.)

(2) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(A) - (C) (No change.)

(D) Productive zone--Any stratum known to contain oil, gas, <u>brine,</u> or geothermal resources in commercial quantities in the area.

(E) - (P) (No change.)

(3) - (5) (No change.)

(6) Well control.

(A) (No change.)

(B) Well control equipment.

(i) (No change.)

(ii) For wells in areas with hydrogen sulfide, the operator shall comply with §3.36 of this title (relating to Oil, Gas, <u>Brine,</u> or Geothermal Resource Operation in Hydrogen Sulfide Areas).

(iii) - (x) (No change.)

(C) - (G) (No change.)

(7) - (10) (No change.)

(b) - (d) (No change.)

§3.16. Log and Completion or Plugging Report.

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) - (3) (No change.)

(4) Well--A well drilled for any purpose related to exploration for or production or storage of oil or gas or brine or geothermal resources, including a well drilled for injection of fluids to enhance hydrocarbon recovery, injection of spent brine return fluids, disposal of produced fluids, disposal of waste from exploration or production activity, or brine mining.

(b) - (e) (No change.)

§3.17. Pressure on Bradenhead.

(a) (No change.)

(b) Any well showing pressure on the Bradenhead, or leaking gas, oil, brine, or geothermal resource between the surface and the production or oil string shall be tested in the following manner. The well shall be killed and pump pressure applied through the tubing head. Should the pressure gauge on the Bradenhead reflect the applied pressure, the casing shall be condemned and a new production or oil string shall be run and cemented. This method shall be used when the origin of the pressure cannot be determined otherwise.

§3.32. Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes.

(a) - (d) (No change.)

(e) Gas Releases to be Burned in a Flare.

(1) (No change.)

(2) Gas releases authorized under this section must be managed in accordance with the provisions of §3.36 of this title (relating to Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas) when applicable.

(3) - (4) (No change.)

(f) - (j) (No change.)

§3.36. Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas.

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon, brine, or geothermal fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon, brine, or geothermal fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) (No change.)

(b) - (e) (No change.)

§3.73. Pipeline Connection; Cancellation of Certificate of Compliance; Severance.

(a) - (i) (No change.)

(j) Pursuant to Texas Natural Resources Code, §91.706(b), if an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been canceled, the Commission may refuse to renew the operator's organization report required by Texas Natural Resources Code, §91.142, until the operator pays the fee required pursuant to §3.78(b)(8) [~~§3.78(b)(9)~~] of this title (relating to Fees and Financial Security Requirements) and the Commission issues the certificate of compliance required for that well.

(k) (No change.)

§3.78. Fees and Financial Security Requirements.

(a) (No change.)

(b) Filing fees. The following filing fees are required to be paid to the Railroad Commission.

(1) - (7) (No change.)

[~~(8) With each application for a permit to discharge to surface water other than a permit for a discharge that meets national pollutant discharge elimination system (NPDES) requirements for agricultural or wildlife use, the applicant shall submit to the Commission a nonrefundable fee of $300.~~]

(8) [~~(9)~~] If a certificate of compliance for a well or a lease [~~an oil lease or gas well~~] has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease

before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) (Statewide Rule 58).

(9) [~~(10)~~] With each application for issuance, renewal, or material amendment of an oil and gas waste hauler's permit, the applicant shall submit to the Commission a nonrefundable fee of $100.

(10) [~~(11)~~] With each Natural Gas Policy Act (15 United States Code §§3301-3432) application, the applicant shall submit to the Commission a nonrefundable fee of $150.

(11) [~~(12)~~] Hazardous waste generation fee. A person who generates hazardous oil and gas waste, as that term is defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall pay to the Commission the fees specified in §3.98(z).

(12) [~~(13)~~] Inactive well extension fee.

(A) For each well identified by an operator in an application for a plugging extension based on the filing of an abeyance of plugging report on Commission Form W-3X, the operator must pay to the Commission a non-refundable fee of $100.

(B) For each well identified by an operator in an application for a plugging extension based on the filing of a fluid level or hydraulic pressure test that is not otherwise required to be filed by the Commission, the operator must pay to the Commission a non-refundable fee of $50.

(13) [~~(14)~~] Groundwater protection determination letters.

(A) With each individual request for a groundwater protection determination letter, the applicant shall submit to the Commission a nonrefundable fee of $100.

(B) With each individual application for an expedited letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.0115(b), the applicant shall submit to the Commission a nonrefundable fee of $75, in addition to the fee required by subparagraph (A) of this paragraph.

(14) [~~(15)~~] An operator must make a check or money order for any of the aforementioned fees payable to the Railroad Commission of Texas. If the check accompanying an application is not honored upon presentment, the Commission or its delegate may suspend or revoke the permit issued on the basis of that application, the allowable assigned, the exception to a statewide rule granted on the basis of the application, the certificate of compliance reissued, or the Natural Gas Policy Act category determination made on the basis of the application.

(15) [~~(16)~~] If an operator submits a check that is not honored on presentment, the operator shall[~~, for a period of 24 months after the check was presented,~~] submit the payment [~~any payments~~] in the form of a credit card, cashier's check, or cash.

(c) - (l) (No change.)

(m) Effect of outstanding violations.

(1) Except as provided in paragraph (2) of this subsection, the Commission shall not accept an organization report or an application for a permit or approve a certificate of compliance for a well or a lease [~~an oil lease or gas well~~] submitted by an organization if:

(A) - (B) (No change.)

(2) - (3) (No change.)

(n) (No change.)

§3.81. Class III Brine Mining Injection Wells.

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings unless, the context clearly indicates otherwise.

(1) - (2) (No change.)

(3) Brine mining injection well--A Class III UIC well used to inject fluid for the purpose of extracting brine by the solution of a subsurface salt formation. The term "brine mining injection well" does not include a well used to inject fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons or the disposal of waste, or a well used to inject fluid for the purpose of extracting sulphur by the thermofluid mining process.

(4) - (11) (No change.)

(b) - (e) (No change.)

(f) Conditions applicable to all permits. The conditions specified in this subsection apply to all permits.

(1) - (17) (No change.)

(18) Plugging. Within one year after cessation of brine mining injection operations, the operator shall plug the well in accordance with §3.14(a) and (c) - (h) [~~(c)(h)~~] of this title (relating to Plugging) (Rule 14(a) and (c) - (h)). For good cause, the director may grant a reasonable extension of time in which to plug the well if the operator submits a proposal that describes actions or procedures to ensure that the well will not endanger fresh water during the period of the extension.

(g) - (l) (No change.)

§3.82. Brine Production Projects and Associated Brine Production Wells and Class V Spent Brine Return Injection Wells.

(a) Scope and purpose.

(1) This section contains the regulations for:

(A) brine production projects and the associated brine production wells for the extraction of elements, minerals, mineral ions, salts, or other useful substances, including, but not limited to, lithium, lithium ions, lithium chloride, halogens or halogen salts, from a subsurface formation but not including oil, gas, or any product of oil or gas, as defined by Section 85.001 of the Natural Resources Code, or fluid oil and gas waste, as defined by Section 122.001 of the Natural Resources Code; and

(B) Class V spent brine return injection wells used in association with brine production projects for the reinjection of the spent brine.

(2) This section applies regardless of whether the well was initially completed for the purpose of brine production or Class V spent brine return injection or was initially completed for another purpose and is converted for brine production or Class V spent brine return injection.

(3) The operator of a brine production project, including associated brine production wells and Class V spent brine return injection wells, shall comply with the requirements of this section as well as with all other applicable Commission rules and orders.

(4) Any pipelines, flowlines, storage, or any other brine containers at the brine production project shall be constructed, operated, and maintained such that they will not leak or cause an unauthorized discharge to surface or subsurface waters.

(5) This section does not apply to Class III brine mining injection wells regulated under §3.81 of this title (relating to Class III Brine Mining Injection Wells).

(6) This section does not apply to the creation, operation, or maintenance of an underground hydrocarbon storage cavern in a salt formation regulated under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) and §3.97 of this title (relating to Underground Storage of Gas in Salt Formations).

(**7**) This section does not apply to the injection of fluids that meet the definition of a hazardous waste under 40 CFR Part 261.

(**8**) Subsection (d) of this section establishes statewide field rules for brine production fields including assignment of acreage, well spacing, and density provisions to promote the regular development of brine resources in a manner that does not damage the reservoir.

(**9**) If a provision of this section conflicts with any provision or term of a Commission order or permit, the provision of such order or permit controls, provided that the provision satisfies the minimum requirements for EPA's Class V Underground Injection Control (UIC) program.

(10) If a provision of this section conflicts with a provision of another Commission rule referenced in this section, the provision of this section controls.

(b) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of activity sought to be permitted, has suffered, or faces a substantial risk of suffering, concrete or actual injury or economic damage other than as a member of the general public. A competitor is not an affected person unless it has suffered, or faces a substantial risk of suffering, actual harm to its interest in real property or waste of substantial recoverable substances.

(2) Application--The Commission form for applying for a permit, including any additions, revisions or modifications to the forms, and any required attachments.

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

(4) Area of review (AOR)--The brine production project area ~~**plus a circumscribing area the width of which is one-quarter mile measured from the perimeter of the brine production project area**~~ **unless an exception obtained pursuant to this section results in an injection well location closer than one-half mile to the boundary of the brine production project area, in which case the area of review is a one-half mile radius around the injection well location.**

(5) Brine--Saline water, whether contained in or removed from an aquifer, which may contain brine resources or other naturally-occurring substances **such as entrained oil or gas, including hydrogen sulfide gas**. The term does not include brine produced as an incident to the production of oil and gas.

(6) Brine field--A formation or the correlative depth interval designated in the field designation or rules that contains brine resources.

(7) Brine production project--A project the purpose of which is the extraction of brine resources from a brine field. The term includes brine production wells, Class V spent brine return injection wells, monitoring wells, brine flowlines, and any equipment associated with the project.

(8) Brine production project area--The surface extent of the land assigned to a brine production project, as indicated on the plat required by subsection (e)(3)(N) of this section.

(9) Brine production project permit--A permit authorizing a brine production project issued by the Commission pursuant to this section.

(10) Brine production well--A well drilled or recompleted for the exploration or production of brine resources that is part of a brine production project.

(11) Brine resource--Elements, minerals, salts, or other useful substances dissolved or entrained in brine, including, but not limited to, lithium, lithium ions, lithium chloride, halogens, or other

halogen salts, but not including oil, gas, or any product of oil or gas. **The term does not include brine extracted pursuant to §3.81 of this title (relating to Class III Brine Mining Injection Wells).**

~~**(12) Casing--A pipe or tubing of appropriate material, of varying diameter and weight, lowered into a borehole during or after drilling to support the sides of the hole and 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.**~~

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

(**14**) Class V spent brine return injection well--A well into which brine produced by a brine production project is re-injected into the same brine field from which it was withdrawn after the brine resources have been extracted. The term does not include a Class I, II, III, IV, or VI UIC well.

(**15**) 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.

(**16**) Commission--The Railroad Commission of Texas ~~**acting through a majority of the Commissioners or through a Commission employee to whom the Commissioners have delegated authority**~~.

(**17**) Confining zone--A geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above or below the brine field.

(**18**) Contaminant--Any physical, chemical, biological, or radiological substance or matter in water.

(**19**) Corrective action--Methods to assure that wells within the area of review do not serve as conduits for the movement of fluids from the brine field and into or between USDWs, including the use of corrosion resistant materials where appropriate.

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

(**21**) Electric log--A density, sonic, or resistivity (except dip meter) log run over the entire wellbore.

(**22**) EPA--The United States Environmental Protection Agency.

(**23**) Exempted aquifer--An aquifer or its portion that meets the criteria in the definition of USDW but which has been exempted according to the procedures in 40 CFR §144.7.

(**24**) Fault--A surface or zone of rock fracture along which there has been displacement.

(**25**) 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.

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

(**27**) 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.

(**28**) Formation fluid--Fluid present in a formation under natural conditions as opposed to introduced fluids such as drilling mud.

(**29**) Fracture pressure--The pressure that, if applied to a subsurface formation, would cause that formation to physically fracture or result in initiation or propagation of fractures.

(**30**) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in an estate that includes the brine resources sought to be extracted through a brine production well.

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

(**32**) Interested person--Any person who expresses an interest in an application, permit, or Class V spent brine return injection 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**) Mechanical integrity--A Class V spent brine return injection well has mechanical integrity if:

(A) there is no significant leak in the casing, tubing, or packer (internal mechanical integrity); and

(B) there is no significant fluid movement into a USDW through channels adjacent to the injection well bore as a result of operation of the injection well (external mechanical integrity).

(**36**) Operator-- A person, acting for itself or as an agent for others and designated to the Commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the Commission.

~~**(37) Owner--The owner of any facility or activity subject to regulation under the UIC program.**~~

(37) Packer--A device lowered into a well to produce a fluid-tight seal.

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

(39) 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.

(40) Plugging record--A systematic listing of permanent or temporary abandonment of water, oil, gas, test, exploration and waste injection wells. The listing may contain a well log, description of amounts and types of plugging material used, the method employed for plugging, a description of formations which are sealed and a graphic log of the well showing formation location, formation thickness, and location of plugging structures.

(41) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(42) Pressure--The total load or force per unit area acting on a surface.

(43) Schedule of compliance--A schedule of remedial measures included in a permit, including an enforceable sequence of interim requirements (for example, actions, operations, or milestone events) leading to compliance with the applicable statutes and regulations.

(44) Spent brine--Brine produced from a brine production well from which brine resources have been extracted. Spent brine may include non-hazardous process water and other additives used to facilitate brine resource extraction or reinjection.

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

(46) Total dissolved solids--The total dissolved (filterable) solids as determined by use of the method specified in 40 CFR part 136.

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

(48) Underground injection--Well injection.

(49) UIC--Underground injection control.

(50) UIC Program--The Underground Injection Control program under Part C of the Safe Drinking Water Act, including an "approved State program" as defined in 40 CFR §144.3.

(51) Underground source of drinking water (USDW)-- An aquifer or its portion which is not an exempted aquifer and which:

(A) supplies any public water system; or

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

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

(ii) contains fewer than 10,000 milligrams per liter total dissolved solids.

(**52**) Well--A bored, drilled, or driven shaft whose depth is greater than the largest surface dimension, or a dug hole whose depth is greater than the largest surface dimension.

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

(**54**) Well plug--A watertight and gastight seal installed in a borehole or well to prevent movement of fluids.

(**55**) 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 section, workovers do not include well stimulation operations.

(c) General requirements.

(1) A brine production project and all associated brine production wells and Class V spent brine return injection wells shall be permitted in accordance with the requirements of this section. No person may construct or operate such wells without a permit under this section.

(2) Applications and reports shall be signed in accordance with this paragraph.

(A) Applications. All applications shall be signed as follows:

(i) for a corporation, by a responsible corporate officer. 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-making or decision-making functions for the corporation; or

(ii) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively.

(B) Reports. All reports required by permits and other information requested by the Commission shall be signed by a person described in subparagraph (A) of this paragraph or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(i) the authorization is made in writing by a person described in subparagraph (A) of this paragraph;

(ii) the authorization specifies an individual or position having responsibility for the overall operation of the regulated **brine production project** ~~facility~~; and

(iii) the authorization is submitted to the Commission before or together with any report of information signed by the authorized representative.

(C) Certification. Any person signing a document under subparagraph (A) or (B) of this paragraph 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 gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are 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."

(3) Operators of all Class V spent brine return injection wells shall re-inject spent brine into the brine field from which the brine was produced.

(4) All brine production wells and Class V spent brine return injection wells shall be drilled and completed or recompleted, operated, maintained, and plugged in accordance with the requirements of this section and the brine production project permit.

(5) The Commission shall assign each brine production project a Commission lease number. All brine project operators shall ascertain from the appropriate schedule the lease number assigned to each separate brine production project, and thereafter include on each Commission-required form or report the exact brine production project name and its assigned number as they appear on the current schedule for all leases.

(6) An applicant for or permittee of a brine production project and associated wells shall comply with the requirements of this chapter, including but not limited to:

(A) §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements);

(B) §3.5 of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back);

(C) §3.11 of this title (relating to Inclination and Directional Surveys Required);

(D) §3.12 of this title (relating to Directional Survey Company Report);

(E) §3.16 of this title (relating to Log and Completion or Plugging Reports)

(F) §3.17 of this title (relating to Pressure on Bradenhead)

(G) §3.18 of this title (relating to Mud Circulation Required);

(H) §3.19 of this title (relating to Density of Mud-Fluid);

(I) §3.36 of this title (relating to Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas); ~~and~~

(J) §3.80 of this title (relating to Commission Oil and Gas Forms, Applications, and Filing Requirements)**; and**

(K) Chapter 4 of this title (relating to Environmental Protection).

(7) In addition to the requirements of §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), all wells associated with a brine production project shall use casing and cement designed to withstand the anticipated pressurization and formation fluids that are capable of negatively impacting the integrity of casing and/or cement such that it presents a threat to USDWs or oil, gas, or geothermal resources.

(8) All operators of wells drilled and operated in association with a brine production project shall comply with the requirements of §3.14 of this title (relating to Plugging), §3.15 (relating to Surface Equipment Removal Requirements and Inactive Wells), and §3.35 (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned), except that the operator shall plug all wells associated with a brine production project and remove all wastes, storage vessels, and equipment from the site within one year of cessation of brine production project operations.

(9) All operators of wells drilled and operated in association with a brine production project shall comply with the requirements of §3.78 of this title (relating to Fees and Financial Security Requirements), as the requirements are applicable to brine production projects, except that, prior to spudding, the operator shall provide financial security in an amount estimated to plug each well in the brine production project after cessation of brine production project operations. Notwithstanding the provisions of §3.78(i) of this title, for an operator of a brine production project who has satisfied its financial security requirements by filing a cash deposit, the Commission shall refund to the operator the amount estimated to plug each well following its plugging if the amount of the deposit remaining after the refund would be sufficient to plug all remaining wells in the brine production project.

(10) No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(d) Spacing, acreage, density and field rules; exceptions.

(1) Spacing. All brine production wells and Class V spent brine return injection wells shall be completed within the brine production project area and no less than one-half mile from the boundary of the brine production project area and no less than one-half mile from any interest within the

brine production project area that is not participating in the project, unless special field rules provide different spacing requirements or the applicant obtains an exception to this paragraph pursuant to paragraph (4) of this subsection.

(2) Acreage and density.

(A) An applicant for a brine production project permit shall designate and assign to the project acreage within the applicable brine field and indicate the total number of acres in the permit application required by subsection (e)(3) of this section. The minimum acreage is 1,280 acres per brine production well included in the brine production project unless special field rules provide different well density requirements or the applicant obtains an exception to this paragraph pursuant to paragraph (4) of this subsection.

(B) Upon completion of a brine production well in a brine production project area and filing the completion report with the Commission, the applicant **shall** ~~may elect to~~ file a plat assigning acreage in the brine production project area to **each** **~~the~~** brine production well**.**~~; however, the applicant is not required to assign acreage to an individual brine production well, provided the~~ **The** total number of acres assigned to the brine production project area divided by the total number of brine production wells **shall equal or exceed** ~~equals or exceeds~~ 1,280 acres unless special field rules provide different well density requirements or the applicant obtains an exception to the density requirements pursuant to paragraph (4) of this subsection.

(C) An applicant shall not assign more than 5,120 acres in a brine field to a brine production well unless special field rules provide for different limits.

(D) **~~If the operator elects to file a plat assigning acreage to a brine production well, the~~** **The** two farthermost points of acreage assigned to **a** ~~the~~ well shall not exceed 23,760 feet unless special field rules provide for a different limit, and the acreage assigned shall include all productive portions of the wellbore.

(E) Multiple assignment of the same acreage in a brine field to more than one brine production well is not permitted. However, this limitation shall not prevent the reformation of brine production projects so long as:

(i) no multiple assignment of acreage occurs; and

(ii) such reformation does not violate other regulations.

(F) The acreage included in a brine production project area shall consist of acreage for which the operator has a good faith claim to produce brine resources.

(i) Non-contiguous acreage included in the same brine production project area may not be separated by greater than the minimum spacing distance for wells provided by paragraph (1) of this subsection, as altered by any applicable special field rules.

(ii) An operator may obtain an exception to the contiguity requirements of clause (i) of this subparagraph pursuant to paragraph (4)(C) of this subsection.

(G) The acreage limits provided by this paragraph are the minimum and maximum amounts of acreage in a brine field that may be assigned to an individual well at the operator's election and shall not be construed as a limit on the sizes of either a brine production project area or a pooled unit for production of brine resources.

(3) Brine field designation and field rules.

(A) Application for new brine field designation. A new brine field designation may be made by the Commission after a hearing after notice to all operators of brine production wells within **a two- and one-half-mile radius** **~~five miles~~** of the brine discovery well. The applicant shall provide proper evidence proving that a well is completed in a new field.

(i) The applicant shall submit a legible area map, drawn to scale, which shows the following:

(I) all oil, gas, brine production, and abandoned wells within at least a **two- and one-half-mile** **~~five-mile~~** radius of the brine well claimed to be a discovery well;

(II) the producing intervals of all wells identified in subclause (I) of this clause;

(III) all Commission-recognized fields within a two and one-half mile radius of the brine well claimed to be a discovery well identified by Commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(IV) the total depth of all wells identified in subclause (I) of this clause that penetrated the top of the proposed new field; and

(V) scale, legend, and name of person who prepared the map.

(ii) The applicant shall submit a list of the names and addresses of all operators of wells within **a two- and one-half-mile radius** **~~five miles~~** of the brine discovery well.

(iii) The applicant shall submit a complete electric log of the brine well. **~~Any electric log filed shall be considered public information pursuant to §3.16 of this title~~. If the applicant contends the electric log is confidential by law, the applicant shall mark the log confidential. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for logs that have been designated confidential, the**

Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the log.

(iv) The applicant shall submit a bottom-hole pressure for brine production wells submitted on the appropriate form. This bottom-hole pressure may be determined by a pressure build-up test, drill stem test, or wire-line formation tester. Calculations based on fluid level surveys or calculations made on flowing wells using shut-in wellhead pressures may be used if no test data is available.

(v) The applicant shall submit a subsurface structure map and/or cross sections, if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the brine field and the lines of cross section. The cross sections shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and brine field identified. The engineer or geologist who prepared the map and cross section shall sign and seal them.

(vi) The applicant shall submit reservoir pressure measurements or calculations, if separation is based on pressure differentials.

(vii) The applicant shall submit core data, drillstem test data, cross sections of nearby wells, and/or production data estimating the fluid level, if separation is based on differences in fluid levels. The applicant shall obtain the fluid level data within 10 days of the potential test date.

(viii) The applicant shall submit evidence that demonstrates that the new brine field is effectively separated from any other brine field or oil or gas field previously shown to be commercially productive.

(B) Temporary brine field rules.

(i) The Commission will accept applications for temporary brine field rule hearings for brine fields after the first well has been completed in a brine field.

(ii) When requesting such hearings, the applicant shall furnish the Commission with a list of the names and addresses of all operators of wells within **a two- and one-half-mile radius** ~~five miles~~ of the brine discovery well.

(iii) At the hearing on the adoption of temporary brine field rules, the applicant bears the burden of establishing that each of the proposed temporary brine field rules is reasonably expected to protect freshwater resources, protect correlative rights, prevent waste of recoverable brine resources, and promote the production of additional brine resources in an orderly and efficient manner.

(iv) Temporary brine field rules shall remain effective until:

(I) 18 months after adoption; or

(II) permanent brine field rules are adopted.

(C) Permanent brine field rules.

(i) After temporary brine field rules have been effective in a brine field for at least 12 months, the operator of a brine production well in the brine field subject to temporary brine field rules or the Commission may request a hearing to adopt permanent brine field rules for the brine field in which the operator's well is located.

(ii) An operator requesting a hearing to adopt permanent brine field rules shall furnish the Commission a list of all operators within **a two- and one-half-mile radius** ~~five miles~~ of the brine discovery well.

(iii) If permanent field rules are not adopted, temporary field rules adopted under subparagraph (B) of this paragraph expire after 18 months and the statewide field requirements of this section apply to operations within the applicable brine field.

(4) Exceptions to spacing, density, and contiguity requirements.

(A) An exception to paragraph (1) of this subsection or paragraph (2)(A) - (C) of this subsection may be granted after ~~a public hearing held after~~ **at least 21 days'** notice to all persons described in subparagraph (B) of this paragraph. An exception to paragraph (2)(F) of this subsection may be granted after **at least 21 days'** ~~a public hearing held after~~ notice to all persons described in subparagraph (C) of this paragraph. **If no person entitled to notice protests the request for an exception, the Commission may grant the exception administratively. If the Commission receives a timely protest, the Director shall forward the request for an exception to the Hearings Division to conduct a hearing.** At a hearing on an exception, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to protect correlative rights.

(B) In addition to the notice required under subsection (f) of this section, an applicant seeking an exception to the spacing or density requirements shall file with its application the names and mailing addresses of the following persons for tracts within the minimum spacing distance for the proposed well and the brine field:

(i) the designated operator;

(ii) all lessees of record for tracts with no designated operator; and

(iii) all owners of record of unleased mineral interests.

(C) In addition to the notice required under subsection (f) of this section, an applicant seeking an exception to the contiguity requirements of paragraph (2)(F) of this subsection shall file with its application the names and mailing addresses of the following persons for tracts located between the non-contiguous portions of its proposed project area that are farther apart than the minimum spacing distance for wells in the brine field:

(i) the designated operator;

(ii) all lessees of record for tracts with no designated operator; and

(iii) all owners of record of unleased mineral interests.

(D) If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this paragraph to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county or counties in which the brine production project well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application.

(e) Brine production project permit application.

(1) Any person who proposes to operate a brine production project shall submit to the Director an application for a brine production project permit. The application shall be made under this section or under special field rules governing the particular brine field, or as an exception thereto, and filed with the Commission on a form approved by the Commission.

(2) An application for a brine production project permit shall be accompanied by an application for at least one injection well and shall include the information required by paragraph (3) of this subsection, as applicable. The applicant is not required to submit permit applications for the other individual brine production and Class V spent brine return injection wells at the time the applicant submits its application for a brine production project permit. Unless otherwise specified in the brine production project permit, once the brine production project permit has been issued, the operator may operate additional brine production wells and Class V spent brine return injection wells as part of the brine production project. The operator shall obtain permits for those wells prior to commencing operations. Requirements for obtaining a Class V spent brine return injection well permit are specified in paragraph (4) of this subsection. Notice in addition to the notice required for the brine production project by subsection (f) of this section is not required for the individual wells unless the operator requests an exception to the spacing, density, or acreage requirements or additional notice is required by the permit.

(3) An application for a brine production project permit shall comply with the requirements of this paragraph.

(A) The application shall include the name, mailing address, and physical location of the brine production project for which the application is submitted.

(B) The application shall include the applicant's name, mailing address, telephone number, P-5 Organization Report number, and a statement indicating whether the applicant operator is the owner of the **brine production project** ~~facility~~.

(C) The application shall specify the proposed use or uses for the brine produced by the project.

(D) The application shall specify the estimated maximum number of brine production wells and Class V spent brine return injection wells that will be operated within the brine production project.

(E) The application shall designate the total number of acres included in the proposed brine production project area, which shall equal not less than 1,280 acres per brine production well unless special field rules provide otherwise.

(F) The application shall specify the brine field from which the brine will be produced and spent brine reinjected, including the top and bottom depths of the field throughout the area of review.

(G) The application shall include complete electric logs of representative brine production wells and Class V spent brine return injection wells or complete electric logs of representative nearby wells. On the logs, the applicant shall identify and indicate the depths of the geologic formations between the land surface and the top of the brine field.

(H) The application shall include wellbore diagrams showing the completions that will be used for brine production wells and Class V spent brine return injection wells, including casing and liner sizes and depths and a statement indicating that such wells will be drilled, cased, cemented, and completed in accordance with the requirements of §3.13 of this title as those requirements may be revised by this section. The statement shall also include information to demonstrate that the casing and cement used in the completion of each brine production well and each Class V spent brine return injection well is designed to withstand the anticipated pressurization and formation fluids that are capable of negatively impacting the integrity of casing and/or cement such that it presents a threat to USDWs or oil, gas, or geothermal resources. The wellbore diagrams shall show the proposed arrangement of the downhole well equipment and specifications of the downhole well equipment. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(I) The application shall include information to characterize the brine field from which the brine will be produced and into which the spent brine will be reinjected, including the following:

(i) an isopach map showing thickness and areal extent of the brine field;

(ii) lithology, grain mineralogy, and matrix cementing of the brine field;

(iii) effective porosity of the brine field and the method used to determine effective porosity;

(iv) vertical and horizontal permeability of the brine field and the method used to determine permeability;

(v) the occurrence and extent of natural fractures and solution features within the brine production project;

(vi) chemical and physical characteristics of the fluids contained in the brine field that may potentially impact casing or cement;

(vii) the bottom hole temperature and pressure of the brine field;

(viii) formation fracture pressure of the brine field, the method used to determine fracture pressure and the expected direction of fracture propagation. Calculations demonstrating injection of spent brine into the proposed brine field shall not exceed the fracture pressure gradient and information showing injection into the brine field will not initiate fractures through the confining zone;

(ix) a description of the proposed well stimulation program, if applicable, including a description of the stimulation fluids, and a determination that the well stimulation will not compromise containment of the brine field;

(x) the vertical distance separating the top of the brine field from the base of the lowest USDW;

(xi) a demonstration, such as geologic maps and cross-sections, that the brine field into which the spent brine will be injected is the same formation from which the brine will be produced; and

(xii) any other information necessary to characterize the brine field.

(J) The application shall include information to characterize the proposed confining zone, including the following:

(i) the geological name and the top and bottom depths of the formation making up the confining zone;

(ii) an isopach map showing thickness and areal extent of the confining zone;

(iii) lithology, grain mineralogy, and matrix cementing of the confining zone;

(iv) the vertical distance separating the top of the confining zone from the base of the lowest USDW; and

(v) any other information necessary to characterize the confining zone.

(K) The application shall include the proposed operating data, including the following:

(i) the maximum daily brine production rate;

(ii) the maximum daily injection rate and maximum injection pressure; and

(iii) the proposed test procedure to be used to determine mechanical integrity of the Class V spent brine return injection wells.

(L) The application shall include a letter from the Geologic Advisory Unit of the Commission's Oil and Gas Division stating that the use of the brine field for the injection of spent brine will not endanger usable quality water or USDWs.

(M) The application shall include an accurate plat with surveys of a scale sufficient to legibly show the entire extent of the area of review. The plat shall include the following:

(i) the area of review outlined on the plat using either a heavy line or crosshatching;

(ii) the location, to the extent anticipated at the time of the application, of each well within the brine production project area that the applicant intends to use for the brine production project including each existing well that may be converted to brine production or Class V spent brine return injection, each well the applicant intends to drill for brine production, each well the applicant intends to drill for project monitoring, and each Class V spent brine return injection well. If the wells are horizontal or deviated wells, the plat shall include the surface location of the proposed drilling site, penetration point, perforated casing or open hole through which brine will be produced or reinjected, terminus location, and a line showing the distance in feet from the perimeter of the area of review to the nearest point of extraction or injection on the lateral leg of the horizontal well;

(iii) the type, location, and depth of all wells of public record within the area of review that penetrate the top of the brine field. The applicant shall include the following information with the map:

(I) a tabulation of the wells showing the dates the wells were drilled and the current status of the wells;

(II) completion records for all wells and plugging records for plugged and abandoned wells; and

(III) a corrective action plan for any known wells in the area of review that penetrate the brine field and that may allow fluid migration into USDWs from the brine field for which the applicant cannot demonstrate proper completion, plugging, or abandonment. The Director may approve a phased corrective action plan;

(iv) the geographic location information of the wells, including the Latitude/Longitude decimal degree coordinates in the WGS 84 coordinate system, a labeled scale bar, and indication of the northerly direction; and

(v) a certification by a person knowledgeable of the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(N) The application shall include a plat showing:

(i) the outline of the brine production project area;

(ii) the operators of tracts in the brine production project area and tracts **adjacent to the brine production project area** ~~**within the area of review**~~;

(iii) owners of all leases of record for tracts that have no designated operator in the brine production project area and **within the brine field** ~~**tracts within the area of review**~~;

(iv) owners of record of unleased mineral interests within the brine field for tracts in the brine production project area ~~**and tracts within the area of review**~~;

(v) surface owners of tracts in the brine production project area ~~**and within the area of review**~~; and

(vi) the names and addresses of all persons listed in clause (ii) through (v) of this subparagraph. If the names and addresses of the persons in clause (ii) through (v) of this subparagraph cannot be included on the plat, the applicant shall include the names and addresses on a separate sheet attached to the plat. The applicant shall determine the names and addresses of the surface owners from the current county tax rolls or other reliable sources and shall identify the source of the list. If the Director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the Director may waive the requirements of this subparagraph with respect to those surface owners.

(O) The application shall include a subsurface structure map and/or cross sections, including faulting and pinch-outs. The structure map shall show the contour of the top of the brine field and the lines of cross section. The cross sections shall be prepared from comparable electric logs (not tracings) and shall identify the wells, brine field, and any hydrocarbon reservoir.

(P) The application shall include a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed injection well location.

(Q) The application shall include a certification that the applicant has a good faith claim to produce the brine resources for the tracts included in the brine production project area.

(R) The application shall include a proposed plugging and abandonment plan.

(S) The applicant shall ensure that, if required under Texas Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, the geologic and hydrologic evaluations required under this section are conducted by a licensed professional engineer or geoscientist who shall affix the appropriate seal on the resulting report of such evaluations.

(T) The application shall include any other information the Director may reasonably require to enable the Commission to determine whether to issue a permit for the brine production project, including the associated brine production wells and Class V spent brine return injection wells.

(4) Prior to commencement of injection operations into any Class V spent brine return injection well within the brine production project area, the operator shall file an application for an individual well permit with the Commission in Austin. The individual well permit application shall include the following:

(A) the well identification and, for a new well, a location plat;

(B) the location of any well drilled within **one-half** ~~one-quarter~~ mile of the injection well after the date of application for the brine production project permit and the status of any well located within **one-half** ~~one-quarter~~ mile of the injection well that has been abandoned since the date the brine production project permit was issued, including the plugging date if such well has been plugged;

(C) a description of the well configuration, including casing and liner sizes and setting depths, the type and amount of cement used to cement each casing string, depth of cement tops, and tubing and packer setting depths;

(D) a description of any additives used in the brine production project and reinjected with the spent brine into the Class V spent brine return well;

(E) an application fee in the amount of $100 per well; and

(F) any other information required by the brine production project permit.

(5) Criteria for exempted aquifers. An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" may be determined under 40 CFR §144.7 to be an "exempted aquifer" if it meets the criteria in paragraphs (a) through (c) of 40 CFR §146.4. The Commission adopts 40 CFR §144.7 and §146.4 by reference, effective ~~January 6~~ **February 19**, 2025.

(6) All individual Class V spent brine return injection wells covered by a brine production project permit shall be completed, operated, maintained, and plugged in accordance with the requirements of subsection (j) of this section and the brine production project permit.

(f) Notice and hearing.

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

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

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

(C) interpretation services accommodated upon request;

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

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

(2) Notice. The applicant for a brine production project permit shall give notice of the application as follows.

(A) Persons to notify. The applicant for a brine production project permit shall notify:

(i) operators on tracts **adjacent to the brine production project area** ~~within the area of review~~;

(ii) owners of all leases of record for tracts that have no designated operator **in the brine production project area and within the brine field** ~~within the area of review~~;

(iii) owners of record of unleased mineral interests **in the brine production project area** ~~within the area of review~~ and within the brine field;

(iv) all surface owners identified on the plat described in subsection (e)(3)(N)**(v)**~~(ii)~~ of this section;

(v) the city clerk or other appropriate city official of a city for which any portion falls within the **brine production project area** ~~**of review**~~;

(vi) the county clerk of any county or counties for which any portion falls within the **brine production project area** ~~**of review**~~; and

(vii) any other person designated by the Director.

(B) Method of notice.

(i) The applicant for a brine production project permit shall mail or deliver to persons listed in subparagraph (A) of this paragraph notice of the brine production project permit application in a form approved by the Commission. The applicant shall provide notice after staff determines than an application is complete pursuant to subsection (g)(1) of this section.

(ii) The applicant shall publish notice of the brine production project permit application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation of any county or counties for which any portion falls within the **brine production project area** ~~**of review**~~. The first notice shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(C) Contents of notice. The notice shall be made using the form prescribed by the Commission, which shall include the following information:

(i) the county or counties within which the brine production project area ~~**of review**~~ is located;

(ii) a copy of the plat required by subsection (e)(3)(M) of this section;

(iii) the name of the brine field;

(iv) the depth to the top of the brine field;

(v) the proposed life of the brine production project; and

(vi) a statement that an affected person may file a protest within 30 days of the date of the notice and any interested person may submit comments to the Commission within 30 days of the date of the notice.

(D) Notice of Class V spent brine return injection wells. Once an applicant complies with the notice required to obtain a brine production project permit and the permit has been issued, no notice shall be required when filing an application for an individual injection well permit for any Class V spent brine return injection well covered by the brine production permit unless otherwise provided in the permit~~.~~ **or unless the individual injection well has an exception such that the injection well is located closer than one-half mile from the boundary of the brine production project, in which case notice shall be provided to any new entity located within the area of review for the injection well**.

(E) Notice of brine production well. Once an applicant complies with the notice required to obtain a brine production permit and the permit has been issued, no notice shall be required when filing an application for an individual brine production well permit for any brine production well covered by the brine production permit unless otherwise provided in the permit or unless an exception is requested.

(3) Comments, protests, and requests for hearing. Notice of an application will allow at least 30 days for public comment. Beginning on the date of the notice, any affected person has 30 days to protest the application, and any interested person has 30 days to submit written comments.

(4) Hearings.

(A) The Commission shall hold a hearing when:

(i) the Commission receives a written protest from an affected person within 30 days after notice of the application is given in accordance with this subsection;

(ii) the Director denies the application and the operator requests a hearing within 30 days of the notice of administrative denial;

(iii) the Director issues the permit and the operator requests a hearing to contest certain permit conditions; or

(iv) the Director determines that a hearing is in the public interest.

(B) Notice of a hearing will be given at least 30 days before the hearing. The public comment period under paragraph (3) of this subsection will automatically be extended to the close of any hearing under this paragraph.

(C) At any hearing, the burden shall be on the applicant.

(D) After hearing, the administrative law judge and technical examiner shall recommend final Commission action.

(g) Commission action on permit applications.

(1) Permitting procedures.

(A) Initial permit application review. Upon receipt of an application for a permit, the Director will review the application for completeness. Within 30 days after receipt of the application, the Director will notify the applicant in writing whether the application is complete or deficient. A notice of deficiency will state the additional information necessary to complete the application, and a date for submitting this information. The application will be deemed withdrawn if the necessary information is not received by the specified date, unless the Director has extended this date upon request of the applicant. Upon timely receipt of the necessary information, the Director will notify the applicant that the application is complete. The Director will not begin processing a permit until the application is complete.

(B) Administrative action on application. When no timely protest is received from an affected person, the Director may administratively grant an application for a brine production project permit, including the associated wells, if the applicant provides sufficient evidence to demonstrate that the brine production project will not endanger USDWs or human health or the environment.

(2) Application for an amended permit. The permittee shall file an application to amend a brine production project permit if the permittee wishes to make substantial changes such as change the exterior boundaries of, or maximum number of wells authorized in, the brine production project area or alter permit conditions.

(3) Permit application denial. If the Director administratively denies a permit application, a notice of administrative denial will be mailed to the applicant. The applicant will have a right to a hearing on request. At any such hearing, the burden shall be on the applicant. After hearing, the administrative law judge and technical examiner shall recommend final Commission action.

(h) Modification, revocation and reissuance, and termination of permits. A permit may be modified, revoked and reissued, or terminated by the Commission either upon the written request of the operator or upon the Commission's initiative, but only for the reasons and under the conditions specified in this subsection. Except for minor modifications made under paragraph (2) of this subsection, the Commission will follow the applicable procedures in paragraph (1) of this subsection. In the case of a modification, the Commission may request additional information or an updated application. In the case of a revocation and reissuance, the Commission will require a new application. If a permit is modified, only the conditions subject to modification are reopened. The term of a permit may not be extended by modification. If a permit is revoked and reissued, the entire permit is reopened and subject to revision, and the permit is reissued for a new term.

(1) Modification, or revocation and reissuance. The following are causes for modification, or revocation and reissuance:

(A) when material and substantial alterations or additions to the **brine production project** ~~facility~~ occur after permit issuance and justify permit conditions that are different or absent in the existing permit;

(B) the Commission receives new information;

(C) the standards or regulations on which the permit was based have been changed by promulgation of amended standards or regulations or by judicial decision after the permit was issued;

(D) the Commission determines good cause exists for modifying a compliance schedule, such as an act of God, strike, flood, materials shortage, or other event over which the operator has little or no control and for which there is no reasonably available remedy;

(E) cause exists for terminating a permit under paragraph (3) of this subsection, and the Commission determines that modification, or revocation and reissuance, is appropriate; or

(F) a transfer of the permit is proposed.

(2) Minor modifications. With the permittee's consent, the Director may make minor modifications to a permit administratively, without following the procedures of paragraph (1) of this subsection. Minor modifications may only:

(A) correct clerical or typographical errors, or clarify any description or provision in the permit, provided that the description or provision is not changed substantively;

(B) require more frequent monitoring or reporting;

(C) change construction requirements provided that any changes shall comply with the requirements of subsection (j)(4) of this section; or

(D) allow a transfer of the permit where the Director determines that no change in the permit is necessary other than a change in the name of the permittee, provided that a written agreement between the current permittee and the new permittee containing a specific **date** ~~data~~ for the transfer of permit responsibility, coverage, and liability has been submitted to the Commission.

(3) Termination. The following are causes for terminating a permit during its term, or for denying a permit renewal application:

(A) the permittee fails to comply with any condition of the permit or this section;

(B) the permittee fails to disclose fully all relevant facts in the permit application or during the permit issuance process, or misrepresents any relevant fact at any time;

(C) a material change of conditions occurs in the operation or completion of the well, or there are material changes in the information originally furnished; or

(D) the Commission determines that the permitted injection endangers human health or the environment, or that pollution of USDWs is occurring or is likely to occur as a result of the permitted injection.

(4) Duty to provide information. The permittee shall also 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 permittee shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.

(i) Permit conditions.

(1) Access by Commission. The permittee shall allow any member or employee of the Commission, on proper identification, to:

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

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

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

(D) 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.

(2) Commission testing. The Commission may make any tests on any well at any time necessary for regulation of wells under this section, and the operator of such wells shall comply with any directives of the Commission to make such tests in a proper manner.

(3) Duty to comply. The permittee shall comply with all conditions of the permit. Any permit noncompliance is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

(4) Need to halt or reduce activity not a defense. It is not 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 the permit.

(5) Duty to mitigate. The permittee shall take all reasonable steps to minimize and correct any adverse effect on the environment resulting from noncompliance with the permit.

(6) 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, that are installed or used by the permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up and auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(7) Property rights. The permit does not convey any property rights of any sort, or any exclusive privilege. However, a valid permit is a property interest that may not be modified, suspended, or revoked without due process of law.

(8) Financial assurance. The permit shall require the permittee to maintain financial responsibility and resources to plug and abandon all brine mining production wells and Class V spent brine return injection wells and to remove all wastes, storage vessels, and equipment from the site within one year of cessation of brine production operations. The permittee shall show evidence of such financial responsibility to the Director in accordance with the requirements of §3.78 of this title by submitting a cash deposit, **an individual** performance bond, **a blanket performance bond,** or letter of credit in a form prescribed by the Commission. Such **cash deposit,** bond**,** or letter of credit shall be maintained until the well is plugged in accordance with paragraph (16) of this subsection.

(9) Duration. A permit issued under this section is effective for the duration of the brine production project. The Commission will review each permit issued pursuant to this section at least once every five years to determine whether just cause exists for modification, revocation and reissuance, or termination of the permit. The Commission may modify, revoke and reissue, or terminate a permit for just cause only after notice and opportunity for a hearing.

(10) Transfers. A brine production project permit is not transferable to any person except by modification, or revocation and reissuance of the permit to change the name of the permittee and incorporate other necessary requirements associated with the permittee name change.

(11) Permit renewal. Any person who has obtained a permit under this section and who wishes to continue to operate the brine production project and brine production wells after the permit expires shall file an application for a new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the Director.

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

(13) Compliance with permit. All brine production wells and Class V spent brine return injection wells shall be drilled, converted, completed, operated, or maintained in accordance with the brine production project permit.

(14) Monitoring and records.

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

(B) The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for at least **five** ~~**three**~~ years from the date **brine production ceases** ~~**of the sample, measurement, report, or application**~~. This period may be extended by the Commission at any time.

(C) Records of monitoring information shall include the date, exact place, and time of the sampling or measurements; the individuals who performed the sampling or measurements; the dates analyses were performed; the individuals who performed the analyses; the analytical techniques or methods used; and the results of the analyses.

(15) Reporting and record retention.

(A) The permittee shall submit to the Director, within the time specified by the Director, any information that the Director may reasonably request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept under the conditions of the permit.

(B) The permittee shall retain records of all information required by the permit for at least five years from the date **brine production ceases** ~~**of commencement of brine production**~~. This period may be extended by request of the Commission at any time.

(C) The permittee shall file a report of the volumes of brine, oil, and gas produced by each brine production well during the preceding month. **The permittee shall report the volumes of brine production on a form designated by the Commission. The permittee shall report oil or gas volumes on the Form PR, Monthly Production Report. Each** ~~The~~ report shall be filed with the Commission **on or before the last** ~~by the 15th calendar~~ day of the month following the period covered by the report.

(D) The permittee shall notify the Director at such times as the permit requires before conversion or abandonment of a well associated with a brine production project.

(E) The permittee shall report to the Commission any noncompliance, including any spills or leaks from brine receptacles or pipelines, that may cause waste or confiscation of property or endanger surface or subsurface water, human health or the environment.

(i) An oral report shall be made to the appropriate district office immediately after the permittee becomes aware of the noncompliance.

(ii) A written report shall be filed with the Director and the appropriate district office within five days of the time the permittee becomes aware of the noncompliance. The written report shall contain the following information:

(I) a description of the noncompliance and its cause;

(II) the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and

(III) steps planned or taken to reduce, eliminate, and prevent recurrence of the noncompliance.

(F) If the permittee becomes aware that it failed to submit any relevant facts or submitted incorrect information in a permit application or a report to the Commission, the permittee shall promptly submit the relevant facts or correct information.

(16) Plugging. The operator of a brine production project shall plug all wells associated with the brine production project in accordance with the provisions of §3.14 of this title, except that the well shall be plugged within one year after cessation of the brine production project. For good cause, the Director may grant a reasonable extension of time in which to plug the wells if the operator submits a proposal that describes actions or procedures to ensure that the wells will not endanger USDWs during the period of the extension.

(17) Identification. Each property that produces brine resources and each well associated with a brine production project and tank shall at all times be clearly identified as follows.

(A) A sign shall be posted at the principal entrance to each such property which shall show the name by which the property is commonly known and is carried on the records of the Commission, the name of the permittee, and the number of acres in the property.

(B) A sign shall be posted at each well site which shall show the name of the property, the name of the permittee, and the well number.

(C) A sign shall be posted at or painted on each tank that is located on or serving each property, which signs shall show, in addition to the information provided for in subparagraph (A) of this paragraph, the Commission lease number for the formation from which brine in the tank is produced.

(D) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by subparagraphs (A), (B), and (C) of this paragraph shall be in letters and numbers at least one inch in height.

(18) Dikes or **berms** ~~fire walls~~. Dikes or **berms** ~~fire walls~~ shall be erected and maintained around all permanent tanks, or battery of tanks, that are:

(A) within the corporate limits of any city, town, or village;

(B) closer than 500 feet to any highway or inhabited dwelling;

(C) closer than 1,000 feet to any school or church; or

(D) so located as to be deemed by the Commission to be an objectionable hazard.

(19) Additional conditions. The Commission reserves the right to include additional permit conditions if it determines the conditions are necessary to ensure compliance with the requirements in this section and to prevent waste, prevent the confiscation of property, or prevent pollution.

(j) Additional permit conditions for Class V spent brine return injection wells. In addition to the conditions in subsection (i) of this section, Class V spent brine return injection wells shall be subject to the following.

(1) Unauthorized injection prohibited. No person may operate a Class V spent brine return injection well without obtaining a permit from the Commission under this section. No person may begin constructing a new Class V spent brine return injection well until the Commission has issued a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title and a permit to operate the injection well under this section.

(2) Injected fluid restricted to brine field. No person may operate a Class V spent brine return injection well in a manner that allows fluids to escape into USDWs from the brine field from which it was produced. If fluids from a Class V spent brine return injection well are migrating out of the brine field into USDWs, the permittee shall immediately cease injection operations in the well or wells most proximate to the location where fluids have been detected in USDWs and perform the necessary corrective action or plug the injection well.

(3) Permit standards. No person may operate a Class V spent brine return injection well in a manner that allows fluid to escape from the permitted brine field or the movement of fluids containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation or may otherwise adversely affect the health of persons. If injected fluids migrate into USDWs, or cause formation fluid to migrate into USDWs, the permittee shall immediately cease injection operations. All permits for Class V spent brine return injection wells issued under this section shall include the conditions required by this section and any other conditions reasonably necessary to prevent the pollution of USDWs.

(4) Construction requirements for Class V spent brine return injection wells. All Class V spent brine mining injection wells shall be drilled and completed or recompleted, operated, maintained, and plugged in accordance with the requirements of this section and the Class V spent brine return injection well permit.

(A) Permits shall specify drilling and construction requirements to assure that the injection operations shall not endanger USDWs. No changes to the construction of a well may be physically incorporated into the construction of the well prior to approval of the modifications by the Director.

(B) In addition to the casing and cementing requirements of §3.13 of this title, the operator shall:

(i) for all newly drilled Class V spent brine return injection wells, drill a sufficient depth into the brine field to ensure that when the well is logged prior to setting the long string the operator will be able to identify the top of the brine field and verify that the fluid will be injected only into the brine field;

(ii) set and cement surface casing from at least 100 feet below the lowermost base of usable quality water as defined by the Geologic Advisory Unit to the surface, regardless of the total depth of the well;

(iii) set and cement long string casing at a minimum from the top of the brine field to the surface unless the Director approves an alternate completion for good cause; and

(iv) determine the integrity of the cement by a cement bond log.

(C) In order to provide the Commission with an opportunity to witness the setting and cementing of the surface casing and production casing (long string) and running of cement bond logs, the operator shall provide at least **48 hours'** ~~15 days'~~ notice to the appropriate Commission district office.

(D) Appropriate logs and other tests shall be conducted during the drilling and construction of a Class V spent brine return injection well to verify the depth to the top of the brine field, adequacy of cement behind the casing strings, and injectivity and fracture pressure of the brine field. A descriptive report interpreting the results of such logs and tests shall be prepared by a knowledgeable log analyst and submitted to the Director. The logs and tests appropriate to each well shall be determined based on the depth, construction, and other characteristics of the well, the availability of similar data in the area, and the need for additional information that may arise as the construction of the well progresses.

(E) The well shall be equipped with tubing and packer set within 100 feet of the top of the brine field.

(F) The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(G) Injection operations may not begin in any new Class V spent brine return injection well until the operator has submitted a completion report to the Director, and the Director has reviewed the completion report and found the well to be in compliance with this section and the conditions of the permit. **If the permittee has not received notice from the Director that the well is in compliance with this section and the permit within 45 days of submission of the completion report, the permittee may begin injection operations.**

(5) Operating requirements. Class V spent brine return injection well permits will prescribe operating requirements, which shall at a minimum specify the following.

(A) All Class V spent brine return injection shall be into the same brine field from which the brine was extracted by the brine production wells.

(B) All injection shall be through tubing set on a packer. The packer shall be set within 100 feet of the top of the permitted injection interval. The Director will consider granting exceptions to this requirement for good cause and when the proposed completion of the well would still result in the protection of underground sources of drinking water and confinement of injected fluids. For wells that are approved for casing injection, the operator shall perform a casing pressure test against a temporary packer/plug to demonstrate mechanical integrity of the long string casing.

(C) Except during well stimulation, injection pressure at the wellhead shall not exceed the maximum pressure calculated to assure that the injection pressure does not initiate new fractures or propagate existing fractures in the brine field and in no case may the injection pressure initiate fractures in the confining zone or cause the escape of injection or formation fluids from the brine field.

(D) The operator shall fill the annulus between the tubing and long string casing with a corrosion inhibiting fluid. All injection wells shall maintain an annulus pressure sufficient to indicate mechanical integrity unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs. The annulus pressure shall be monitored by a pressure chart or digital pressure gauge. The operator shall provide the Director with a written report and explanation of any change in annulus pressure that would indicate a leak or lack of mechanical integrity~~**, such as an annulus pressure change exceeding 10%,**~~ within 15 days of detecting the change in pressure. **The Commission will consider any deviations that cannot be explained by factors such as temperature fluctuations or a reasonable margin of error to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a formation containing a USDW.** An unsatisfactory explanation may result in a requirement that the well be tested for mechanical integrity.

(E) For each workover of an injection well, the operator shall notify the appropriate Commission district office at least 48 hours prior to the beginning of the workover or corrective maintenance operations that involve the removal of the tubing or well stimulation, and a mechanical integrity test shall be run on the well after the workover is completed if the packer is unseated during the workover.

(6) Corrective action. For all known wells in the area of review that penetrate the top of the brine field for which the operator cannot demonstrate proper completion, plugging, or abandonment, the Director will require corrective action if necessary to prevent movement of fluid into USDWs. Corrective action may be phased, if a phased corrective action plan has been approved by the Director.

(7) Mechanical integrity of Class V spent brine return injection wells.

(A) Mechanical integrity required. No person may perform injection operations in a Class V spent brine return injection well that lacks mechanical integrity. A well has mechanical integrity if:

(i) there is no significant leak in the casing (internal mechanical integrity); and

(ii) there is no significant fluid movement into a USDW through vertical channels adjacent to the wellbore (external mechanical integrity).

(B) Mechanical integrity shall be demonstrated to the satisfaction of the Director. In conducting and evaluating the results of a mechanical integrity test, the operator and the Director shall apply procedures and standards generally accepted in the industry. In reporting the results of a mechanical integrity test, the operator shall include a description of the method and procedures used. In evaluating the results, the Director will review monitoring and other test data submitted since the previous mechanical integrity test.

(C) Internal mechanical integrity. The permittee shall provide for a demonstration of internal mechanical integrity of the wellhead, casing, tubing, and annular seal assembly if present, using either a pressure test at a surface pressure of not less than 100 psig above the maximum expected operating surface pressure of the well or an equivalent test approved by the Director. The permittee shall provide a recording device to record the pressures measured during a mechanical integrity test.

(D) External mechanical integrity. The permittee shall use one of the following methods to demonstrate the absence of significant fluid movement into USDWs through vertical channels adjacent to the Class V spent brine return injection wellbore:~~.~~

(i) the results of a temperature or noise log; or

(ii) where the nature of the casing precludes the use of the logging techniques prescribed in clause (i) of this subparagraph, cementing records demonstrating the presence of adequate cement to prevent such movement.

(E) Alternate methods. The Director may allow the use of a method of demonstrating mechanical integrity other than the methods listed in subparagraphs (C) and (D) of this paragraph with the approval of the administrator of EPA obtained pursuant to 40 CFR §146.8(d).

(F) Calibration of pressure gauges. A permittee shall calibrate all pressure gauges used in mechanical integrity demonstrations according to the manufacturer's recommendations. A copy of the calibration certificate shall be submitted to the Director at the time of demonstration and every time the gauge is calibrated. A pressure gauge shall have a resolution so as to allow detection of at least one-half of the maximum allowable pressure change.

(G) Timing of mechanical integrity testing.

(i) Both internal and external mechanical integrity shall be demonstrated before injection operations begin.

(ii) Internal mechanical integrity shall be demonstrated annually thereafter and after any workover that involves the removal of the tubing.

(iii) External mechanical integrity shall be demonstrated every five years.

(iv) The Director may require mechanical integrity testing if the Director has reason to believe that the well lacks mechanical integrity.

(H) Notice of testing.

~~(i)~~ The permittee shall notify the appropriate Commission district office orally at least 48 hours before performance of a mechanical integrity test.

~~(ii) The permittee shall notify the Director in writing within 15 days of a failed mechanical integrity test. The notice shall indicate the permittee's plans for performing corrective action and re-testing the well or plugging the well.~~

(I) Reporting of testing. The permittee shall file a complete record of the test with the Commission in Austin within 30 days after the test. A copy of the pressure record shall accompany the report. The report shall include evaluation of the test results by a person qualified to provide such an evaluation. Reports of mechanical integrity demonstrations using downhole logs shall be accompanied by an interpretation of the log by a person qualified to make such interpretations.

(J) Failure to demonstrate mechanical integrity.

(i) A well shall maintain mechanical integrity. If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity is suspected during operation, the permittee shall halt injection immediately unless the Director allows continued injection because the permittee establishes that injection can continue without endangering USDWs. Report of the failure of mechanical integrity shall be made orally to the Director within 24 hours from the time the permittee becomes aware of the failure~~**, and shall include an anticipated date for a mechanical integrity demonstration**~~.

(ii) A written plan to restore mechanical integrity shall be submitted to the Director within 15 days of the failure to demonstrate mechanical integrity. The plan shall include a schedule and description of corrective action and a schedule for re-testing or plugging the well. The corrective action proposed in the plan shall be designed such that the completion of the well will comply with this section. The Director may witness any mechanical integrity demonstration.

(iii) ~~(ii)~~ All wells that fail to pass a mechanical integrity test shall be repaired or plugged and abandoned within 90 days of the failure date. The 90-day timeline may be extended by the Director for good cause. The well **shall** ~~is to~~ be shut-in immediately after failure to pass the mechanical integrity test and shall remain shut-in until it passes a mechanical integrity test or is plugged and abandoned.

~~**(iii) If injection has ceased as provided by clause (i) of this subparagraph, then the permittee shall not resume injection until the well demonstrates mechanical integrity. A written plan to restore mechanical integrity shall be submitted to the Director within 15 days of the failure of mechanical integrity. The plan shall include a schedule and description of corrective action and a schedule for re-testing or plugging the well. The plan shall be approved by the Director and the Director may witness any mechanical integrity demonstration.**~~

(K) Testing deviations. The Commission will consider any deviations during testing that cannot be explained by factors such as temperature fluctuations or by the margin of error for the test used to determine mechanical integrity to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a formation containing a USDW ~~**through channels adjacent to the injection wellbore.**~~

(8) Monitoring and records.

(A) Monitoring requirements. Permits shall specify the following monitoring requirements:

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

(ii) the type, intervals, and frequency of monitoring sufficient to yield data representative of the monitored activity, including continuous monitoring when appropriate;

(iii) the reporting of monitoring results with a frequency dependent on the nature and effect of the monitored activity, but in no case less than annually; and

(iv) any samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

(B) Record retention. The operator shall retain records of all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for at least **five** ~~**three**~~ years from the date **brine production ceases** ~~**of the sample, measurement, report, or application**~~. This period may be extended by request of the Commission at any time.

(C) Monitoring record contents. Records of monitoring information shall include the date, exact place, and time of the sampling or measurements; the individuals who performed the sampling or measurements; the dates analyses were performed; the individuals who performed the analyses; the analytical techniques or methods used for the analyses; and the results of the analyses.

(D) Signatory requirements. All reports and other information submitted to the Commission shall be signed and certified in accordance with subsection (c)(2) of this section.

(E) Reporting requirements.

(i) The operator shall notify the Commission and obtain Commission approval in advance of any planned changes to the brine production project, including any physical alternation or addition to the project and any change that may result in non-compliance with permit conditions.

(ii) Monitoring results shall be reported at the intervals specified in the permit.

(iii) Reports of compliance or noncompliance with the requirements contained in any schedule of compliance shall be submitted no later than 30 days after each scheduled date.

(iv) The operator shall report to the Commission any noncompliance that may endanger USDWs, human health, or the environment.

(I) An oral report shall be made to the appropriate Commission district office immediately after the operator becomes aware of the noncompliance.

(II) A written report shall be filed with the Director within five days of the time the operator becomes aware of the noncompliance. The written report shall contain the following information:

(-a-) a description of the noncompliance and its cause;

(-b-) the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and

(-c-) steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(v) Information that shall be reported under this subparagraph includes the following:

(I) any monitoring or any other information that indicates that any contaminant may endanger USDWs; and

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

(F) Reporting errors. If the operator becomes aware that it failed to submit any relevant facts or report any noncompliance, or that it submitted incorrect information in a permit application or a report to the Director, then the operator shall promptly submit the relevant facts, report of noncompliance, or correct information as applicable. A report of noncompliance shall contain the information listed in subparagraph (E) of this paragraph.

(9) Notice of workovers. The operator shall notify the appropriate Commission district office at least 48 hours before performing any workover or corrective maintenance operations that involve the unseating of the packer or well stimulation.

(10) Additional conditions. The Commission may establish additional conditions on a case-by-case basis as required to provide for and assure compliance with the requirements specified in this section.

(k) Violations; penalties.

(1) Any well drilled or operated in violation of this section without a permit issued under this section shall be plugged.

(2) Violations of this section may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3.

(3) The certificate of compliance for a brine production well may be revoked in the manner provided in subsections §3.73(d)-(g), (i)-(k) of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance) for violations of this section.

(l) Commission review of administrative actions. Administrative actions performed by the Director or Commission staff pursuant to this section are subject to review by the commissioners.

(m) Federal regulations. All references to the CFR in this section are references to the 1987 edition of the Code. The following federal regulations are adopted by reference and can be obtained at the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78711: 40 CFR §§124.8(b), 124.10(c)(1)(viii), 124.10(d), and 146.8(d). Where the word "director" is used in the adopted federal regulations, it should be interpreted to mean "commission."

(n) Effective date. For the regulations pertaining to Class V spent brine return injection wells, this section becomes effective upon approval of the Commission's Class V Underground Injection Control (UIC) Program for spent brine return injection wells by the USEPA under the Safe Drinking Water Act, §1422 (42 United States Code §300h-1). For all other regulations, this section becomes effective as provided in Section 2001.001 et seq. of the Texas Government Code.

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 January 29, 2025.

Filed with the Office of the Secretary of State on January 29, 2025.

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