Adopted rules include new rules, amendments to existing rules, and repeals of existing rules. A rule adopted by a state agency takes effect 20 days after the date on which it is filed with the Secretary of State unless a later date is required by statute or specified in the rule (Government Code, §2001.036). If a rule is adopted without change to the text of the proposed rule, then the *Texas Register* does not republish the rule text here. If a rule is adopted with change to the text of the proposed rule, then the final rule text is included here. The final rule text will appear in the Texas Administrative Code on the effective date.

TITLE 16. ECONOMIC REGULATION

PART 1. RAILROAD COMMISSION OF TEXAS

CHAPTER 1. PRACTICE AND PROCEDURE

SUBCHAPTER I. PERMIT PROCESSING

16 TAC §1.201

The Railroad Commission of Texas (Commission) adopts amendments to §1.201, relating to Time Periods for Processing Applications and Issuing Permits Administratively, with changes to the proposed text as published in the November 1, 2024, issue of the *Texas Register* (49 TexReg 8647). The Commission adopts the amendments to update cross-references to other Commission rules in the rule and in the table, as well as other nonsubstantive clarifications.

The Commission received one comment from the Texas Pipeline Association (TPA). TPA specifically commented on the entry in the table regarding §3.70 (SWR 70), Pipeline Permits Required, Permit to Operate a Pipeline. TPA stated it is unclear whether the 21-day Initial Review Period and the 15-day Final Review Period are meant to be taken in the aggregate and potentially exceeding 30 days, or if it is meant to indicate that each period may take no longer than the specified time, and in no event shall the aggregate exceed 30 days. TPA's understanding is that Commission staff intends for the maximum period for approval to remain 30 days. TPA recommends a modification to the table to reflect this intention.

The Commission agrees with TPA's comment and adopts the figure with a change to the entry to §3.70 to indicate the correct timelines.

The Commission adopts an additional change to the figure to remove the row for §3.82, Permit for Brine Production Projects and Associated Class V Spent Brine Return Wells. This row was proposed to be added pursuant to a separate rulemaking which has not yet been finalized; therefore, the Commission adopts the figure to remove that row.

The Commission amends §1.201(a) to more closely align with Government Code §2005.003, the statute which requires adoption of §1.201. The amendments clarify that §1.201 does not apply to all permits issued by the Commission, but only those permits for which the median time for processing a permit application from receipt of the initial application to the final permit decision exceeds seven days. The amendments also replace the definition of "permit" with a reference to Government Code §2005.003 to ensure the Commission's rule is consistent with the statutory definition of the term.

The table in §1.201(a) is amended to reflect current permits, operating division names, and permit processing time periods. Sections 3.8 (relating to Water Protection) and 3.57 (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials) are currently adopted in a separate Commission rulemaking. Thus, the obsolete sections of those rules and the permits issued pursuant to those rules are removed from the table in §1.201(a). The amendments also correct other outdated references and remove permits the Commission no longer issues.

The Commission also restructures the table to limit the information for each permit to: (1) the permit and rule or law governing the permit; (2) the Commission division responsible for processing the permit; and (3) the initial and final review periods as required by Government Code §2005.003. The previous table included information on Commission forms and fees associated with the permits. However, form and fee information is more easily obtained from the Commission's website. The Commission's website is more frequently updated and allows more information about each permit to be accessible to persons seeking a permit from the Commission. The amendments to the table also remove column names to simplify future updates. Column name references are removed throughout the section and are replaced with general references to the table.

Several permit types are also removed from the table because the permit processing time no longer exceeds seven days, the permit type is no longer issued, or the authorization does not meet the definition of a permit under Government Code §2005.003.

Finally, the Commission adopts amendments in §1.201(c)(7) and (e) to reflect the current name of the division which contains the Docket Services Section.

The Commission adopts the amendments under Texas Government Code §2005.003, which requires a state agency that issues permits to adopt procedural rules for processing permit applications and issuing permits; Texas Government Code §2001.004, which requires a state agency to adopt rules of practice stating the nature and requirements of all available formal and informal procedures; and 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.

Statutory Authority: Texas Government Code §§2005.003 and 2001.004; Texas Natural Resources Code §§81.051 and 81.052.

Cross-reference to statute: Texas Government Code Chapters 2001 and 2005; Texas Natural Resources Code Chapter 81.

§1.201. Time Periods for Processing Applications and Issuing Permits Administratively.

(a) Applicability. This rule applies to permits issued administratively by the Commission through the operating divisions listed in Table 1 of this section and for which the median permit processing time exceeds seven days. These permits are listed in Table 1 of this section. For purposes of this rule, the term "permit" has the meaning assigned in Texas Government Code Chapter 2005.
Figure: 16 TAC §1.201(a)

(b) Completeness. An application is complete when the division or section shown in Table 1 has determined that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the division or section processing the application. For purposes of this section, certain applicants are required to have an approved organization report (Form P-5) on file with the Commission in order for an application to be complete.

(c) Time periods.

(1) The date a permit application is received under this section is the date the application reaches the designated division or section within a division as shown in Table 1.

(2) The division or section shown in Table 1 shall process permit applications in accordance with the time periods shown in Table 1 for a particular permit. Time periods are counted on the basis of calendar days.

(3) The Initial Review Period, shown in Table 1, begins on the date the designated division or section receives the application and ends on the date the division or section gives written notice to the applicant indicating that either:

(A) the application is complete and accepted for filing; or

(B) the application is incomplete, as described in paragraph (4) of this subsection.

(4) If the division or section determines that an application is incomplete, the division or section shall notify the applicant in writing and shall describe the specific information required to complete the application. An applicant may make no more than two supplemental filings to complete an application. The Initial Review Period shall start again each time the division or section receives a supplemental filing relating to an incomplete application. After the second supplemental submission, if the application is complete, the division or section shall administratively rule on the application; if the application is still incomplete, the division or section shall administratively deny the application. The division or section specifically does not have the authority to accept or review any other additional supplemental submissions. The division or section shall notify the applicant in writing of the administrative decision and, in the case of an administrative denial, the applicant's right to request a hearing on the application as it stands. The applicant may withdraw the application.

(5) The Final Review Period, shown in Table 1, begins on the date the division or section makes a determination under paragraph (3)(A) of this subsection and ends on the date the permit is:

(A) administratively granted;

(B) administratively denied; or

(C) docketed as a contested case proceeding if the application is neither administratively granted nor administratively denied.

(6) An applicant whose application has been administratively denied may request a hearing by filing a written request for a hearing addressed to the division or section processing the application, within 30 days of the date the application is administratively denied.

(7) Within seven days of either docketing an application under paragraph (5)(C) of this subsection or receiving a written request for a hearing under paragraph (6) of this subsection, the division or section processing the application shall forward the file and any request for hearing, including any memoranda or notes explaining or describing the reasons for docketing or administrative denial, to the Docket Services Section of the Hearings Division, which shall process the application as prescribed in subsection (e) of this section.

(d) Complaint procedure.

(1) An applicant may complain directly to the Executive Director if a division or section does not process an application within the applicable time periods shown in Table 1, and may request a timely resolution of any dispute arising from the claimed delay. All complaints shall be in writing and shall state the specific relief sought, which may include the full reimbursement of any fee paid in that particular application process. As soon as possible after receiving a complaint, the Executive Director shall notify the appropriate division director of the complaint.

(2) Within 30 days of receipt of a complaint, the division director of the division or section processing the application that is the subject of the complaint shall submit to the Executive Director a written report of the facts relating to the processing of the application. The report shall include the division director's explanation of the reason or reasons the division or section did or did not exceed the established time periods. If the Executive Director does not agree that the division or section has violated the established periods or finds that good cause existed for the division or section to have exceeded the established periods, the Executive Director may deny the relief requested by the complaint.

(3) For purposes of this section, good cause for exceeding the established period means:

(A) the number of permit applications to be processed by the division or section exceeds by at least 15 percent the number of permit applications processed by that division or section in the same quarter of the previous calendar year;

(B) the division or section must rely on another public or private entity to process all or part of the permit application received by the agency, and the delay is caused by that entity; or

(C) other conditions exist that give the division or section good cause for exceeding the established period, including but not limited to circumstances such as personnel shortages, equipment outages, and other unanticipated events or emergencies.

(4) The Executive Director shall make the final decision and provide written notification of the decision to the applicant and the division or section within 60 days of receipt of the complaint.

(e) Hearings. If an application is docketed as a contested case proceeding, it is governed by the time periods in this chapter (relating to Practice and Procedure) once the application has been filed with the Docket Services Section of the Hearings Division.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 17, 2024.

TRD-202406061

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Effective date: January 6, 2025
Proposal publication date: November 1, 2024
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CHAPTER 3. OIL AND GAS DIVISION

16 TAC §§3.8, 3.14, 3.22, 3.30, 3.57, 3.91, 3.98

The Railroad Commission of Texas (Commission) adopts amendments to §§3.8, 3.14, 3.22, 3.30, 3.57, 3.91, and 3.98, relating to Water Protection; Plugging; Protection of Birds; Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ); Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials; Cleanup of Soil Contaminated by a Crude Oil Spill; and Standards for Management of Hazardous Oil and Gas Waste, without changes to the proposed text as published in the August 30, 2024, issue of the *Texas Register* (49 TexReg 6545); the rule text will not be republished. The Commission adopts amendments to §3.8 and §3.57 to remove all substantive language from the rules and replace with notice that the requirements are relocated to Chapter 4 of this title (relating to Environmental Protection) which is adopted in a concurrent rulemaking. Other adopted amendments update cross-references to certain Commission rules in conjunction with the new and amended rules in Chapter 4.

To align with the concurrent amendments and new rules in Chapter 4, the Commission adopts the amendments in §3.8 and §3.57 to go into effect July 1, 2025, which is approximately six months after the adoption of the amendments.

The Commission received numerous comments regarding the concurrent rulemaking in Chapter 4 which are addressed in that preamble, but only three comments from two individuals and one company addressing the proposed rules in Chapter 3.

One individual commented regarding distilled water, stating that the definition of distilled water was moved from §3.8 to Chapter 4, but the text in §3.8(d)(7)(B) did not appear to be moved to Chapter 4. The individual requested clarification regarding whether the activities allowed under §3.8(d)(7)(B) would continue to be allowed.

As stated in the Chapter 4 adoption preamble, the Commission notes that with the recent attention to the development of technology and logistics to treat and recycle produced water, some of which include distillation methods, a blanket authorization to allow distilled water to be reused for any purpose is unwise. Distilled water commonly contains low concentrations of constituents that have passed through distillation, and at this time, it is appropriate to limit the potential for harm from processes that are unproven. Therefore, the Commission does not incorporate the language from §3.8(d)(7)(B) into Chapter 4. The Commission also makes no changes to §3.8 in response to this comment.

One individual commented only that the term "storm water" should be "stormwater." The commenter did not specify a rule, but the term "storm water" is used frequently in §3.30 and other rules. Because the term appears in parts of §3.30 that were not proposed with any changes, the Commission declines to adopt this change in the amendments to rules in Chapter 3. It is unlikely confusion would be caused if the term appears as one word or two.

One company commented on several rules in Chapter 4 and also mentioned the definition of "disposal." Section 3.91 explicitly excludes crude oil spills or releases remediated in accordance with §3.91; however, the company believes these events that are in active remediation are appropriately regulated by §3.91 and should not be additionally governed by the waste disposal provisions in §3.8(d)(1), now moved to §4.103 in the concurrent Chapter 4 rulemaking.

The Commission generally agrees with the concept behind the comment and adopts §4.103(a)(2) to include "as authorized by §3.91 of this title (relating to Cleanup of Soil Contaminated by a Crude Oil Spill)." The Commission disagrees that a change in needed in §3.91 and adopts it without change from the proposal.

The Commission adopts the amendments to pursuant to 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.

Statutory authority: Texas Natural Resources Code §§81.051 and 81.052.

Cross reference to statute: Texas Natural Resources Code Chapter 81.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 17, 2024.

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Effective date: July 1, 2025
Proposal publication date: August 30, 2024
For further information, please call: (512) 475-1295

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CHAPTER 4. ENVIRONMENTAL PROTECTION

The Railroad Commission of Texas (Commission) adopts in Chapter 4, new Subchapter A, relating to Oil and Gas Waste Management, which includes the following new rules: In Division 1, General, the Commission adopts §4.101 (relating to Prevention of Pollution); §4.102 (relating to Responsibility for Oil and Gas Wastes); §4.103 (relating to Prohibited Waste Management Methods); §4.104 (relating to Coordination Between the Commission and Other Regulatory Agencies); §4.106 (relating to Fees); §4.107 (relating to Penalties); §4.108 (relating to Electronic Filing Requirements); and §4.109 (relating to Exceptions). In Division 2, Definitions, the Commission adopts §4.110 (relating to Definitions). In Division 3, Operations Authorized by Rule, the Commission adopts §4.111 (relating to Authorized Disposal Methods for Certain Wastes); §4.112 (relating to Authorized Recycling); §4.113 (relating to Authorized Pits); §4.114 (relating to Schedule A Authorized Pits); and §4.115 (relating to Schedule B Authorized Pits). In Division 4, Requirements for All Permitted Waste Management Operations, the Commission adopts §4.120 (relating to General Requirements for All Permitted Operations); §4.121 (relating to Permit Term); §4.122 (relating to Permit Renewals, Transfers, and Amendments); §4.123 (relating to Permit Modification, Suspension and Termination); §4.124 (relating to Requirements Applicable to All Permit Applications and Reports); §4.125 (relating to Notice and Opportunity to Protest); §4.126 (relating to Location and Real Property Information); §4.127 (relating to Engineering and Geologic Information); §4.128 (relating to Design and Construction); §4.129 (relating to Operation); §4.130 (relating to Reporting); §4.131 (relating to Monitoring); §4.132 (relating to Closure); §4.134 (relating to Application Review and Administrative Decision); and §4.135 (relating to Hearings. In Division 5, Additional Requirements for Commercial Facilities, the Commission adopts §4.140 (relating to Additional Requirements for Commercial Facilities); §4.141 (relating to Additional Notice Requirements for Commercial Facilities); §4.142 (relating to Operating Requirements Applicable to Commercial Facilities); and §4.143 (relating to Design and Construction Requirements for Commercial Facilities). In Division 6, Additional Requirements for Permitted Pits, the Commission adopts §4.150 (relating to Additional Requirements Applicable to Permitted Pits); §4.151 (relating to Design and Construction of Permitted Pits); §4.152 (relating to Monitoring of Permitted Pits); §4.153 (relating to Commercial Disposal Pits); and §4.154 (relating to Closure of Permitted Pits). In Division 7, Additional Requirements for Landfarming and Landtreating, the Commission adopts §4.160 (relating to Additional Requirements for Landfarming and Landtreating Permits); §4.161 (relating to Design and Construction Requirements for Landfarming and Landtreating Permits); §4.162 (relating to Operating Requirements for Landfarming and Landtreating Permits); §4.163 (relating to Monitoring); and §4.164 (relating to Closure). In Division 8, Additional Requirements for Reclamation Plants, the Commission adopts §4.170 (relating to Additional Requirements for Reclamation Plants); §4.171 (relating to Standard Permit Provisions); §4.172 (relating to Minimum Permit Provisions for Operations); and §4.173 (relating to Minimum Permit Provisions for Reporting). In Division 9, Miscellaneous Permits, the Commission adopts §4.180 (relating to Activities Permitted as Miscellaneous Permits); §4.181 (relating to Emergency Permits); §4.182 (relating to Minor Permits); §4.184 (relating to Permitted Recycling); and §4.185 (relating to Pilot Programs). In Division 10, Requirements for Oil and Gas Waste Transportation, the Commission adopts §4.190 (relating to Oil and Gas Waste Characterization and Documentation); §4.191 (relating to Oil and Gas Waste Manifests); §4.192 (relating to Trans-Jurisdictional Waste Transfers; §4.193 (relating to Oil and Gas Waste Haulers); §4.194 (relating to Recordkeeping); and §4.195 (relating to Waste Originating Outside of Texas). In Division 11, Requirements for Surface Water Protection, the Commission adopts §4.196 (relating to Surface Water Pollution Prevention) and §4.197 (relating to Consistency with the Texas Coastal Management Program). Sections 4.101, 4.103, 4.104, 4.110, 4.112 - 4.115, 4.120, 4.125, 4.128, 4.130, 4.131, 4.140, 4.150, 4.152, 4.161, 4.190 - 4.193, 4.195 and 4.196 are adopted with changes from the proposed text as published in the August 30, 2024, issue of the *Texas Register* (49 TexReg 6563). The remaining rules in Subchapter A are adopted without changes from the proposed text and will not be republished.

The new rules in Subchapter A are adopted to incorporate and update the requirements from §3.8 of this title, relating to Water Protection ("Rule 8"), which is amended concurrently with the new rules and amendments in Chapter 4. The new subchapter also ensures Commission rules adhere to statutory changes made in recent legislative sessions.

The Commission also adopts amendments and new rules in Subchapter B, relating to Commercial Recycling, to incorporate legislative requirements and make updates consistent with the new rules in Subchapter A. The Commission amends the following rules in Subchapter B, Division 1: §4.201 (relating to Purpose), §4.202 (relating to Applicability and Exclusions), §4.203 (relating to Responsibility for Management of Waste to be Recycled), §4.204 (relating to Definitions), §4.205 (relating to Exceptions), §4.206 (relating to Administrative Decision on Permit Application), §4.207 (relating to Protests and Hearings), §4.208 (relating to General Standards for Permit Issuance), §4.209 (relating to Permit Renewal), and §4.211 (relating to Penalties); in Division 2, §4.212 (relating to General Permit Application Requirements for On-Lease Commercial Solid Oil and Gas Waste Recycling Facilities), §4.213 (relating to Minimum Engineering and Geologic Information), §4.214 (relating to Minimum Design and Construction Information), §4.218 (relating to General Permit Provisions for On-Lease Commercial Solid Oil and Gas Waste Recycling), §4.219 (relating to Minimum Siting Information), §4.220 (relating to Minimum Permit Provisions for Design and Construction), §4.221 (relating to Minimum Permit Provisions for Operations), §4.222 (relating to Minimum Permit Provisions for Monitoring), §4.223 (relating to Minimum Permit Provisions for Closure), and §4.224 (relating to Permit Renewal); in Division 3, §4.230 (relating to General Permit Application Requirements for Off-Lease or Centralized Commercial Solid Oil and Gas Waste Recycling), §4.231 (relating to Minimum Engineering and Geologic Information), §4.232 (relating to Minimum Siting Information), §4.234 (relating to Minimum Design and Construction Information), §4.238 (relating to Notice), §4.239 (relating to General Permit Provisions), §4.240 (relating to Minimum Permit Provisions for Siting), §4.241 relating to Minimum Permit Provisions for Design and Construction), §4.242 (relating to Minimum Permit Provisions for Operations), §4.243 (relating to Minimum Permit Provisions for Monitoring), and §4.245 (relating to Permit Renewal); in Division 4, §4.246 (relating to General Permit Application Requirements for a Stationary Commercial Solid Oil and Gas Waste Recycling Facility), §4.247 (relating to Minimum Engineering and Geologic Information), §4.248 (relating to Minimum Siting Information), §4.250 (relating to Minimum Design and Construction Information), §4.251 (relating to Minimum Operating Information), §4.254 (relating to Notice), §4.255 (relating to General Permit Provisions), §4.256 (relating to Minimum Permit Provisions for Siting), §4.257 (relating to Minimum Permit Provisions for Design and Construction), §4.258 (relating to Minimum Permit Provisions for Operations), §4.259 (relating to Minimum Permit Provisions for Monitoring), and §4.261 (relating to Permit Renewal); in Division 5, §4.262 (relating to General Permit Application Requirements for Off-Lease Commercial Recycling of Fluid), §4.263 (relating to Minimum Engineering and Geologic Information), §4.264 (relating to Minimum Siting Information), §4.266 (relating to Minimum Design and Construction Information), §4.267 (relating to Minimum Operating Information), §4.268 (relating to Minimum Monitoring Information), §4.269 (relating to Minimum Closure Information), §4.270 (relating to Notice), §4.271 (relating to General Permit Provisions), §4.272 (relating to Minimum Permit Provisions for Siting), §4.273 (relating to Minimum Permit Provisions for Design and Construction), §4.274 (relating to Minimum Permit Provisions for

Operations), §4.275 (relating to Minimum Permit Provisions for Monitoring), §4.276 (relating to Minimum Permit Provisions for Closure), and §4.277 (relating to Permit Renewal); in Division 6, §4.278 (relating to General Permit Application Requirements for a Stationary Commercial Fluid Recycling Facility), §4.279 (relating to Minimum Engineering and Geologic Information), §4.280 (relating to Minimum Siting Information), §4.282 (relating to Minimum Design and Construction Information), §4.283 (relating to Minimum Operating Information), §4.284 (relating to Minimum Monitoring Information), §4.285 (relating to Minimum Closure Information), §4.286 (relating to Notice), §4.287 (relating to General Permit Provisions), §4.288 (relating to Minimum Permit Provisions for Siting), §4.289 (relating to Minimum Permit Provisions for Design and Construction), §4.290 (relating to Minimum Permit Provisions for Operations), §4.291 (relating to Minimum Permit Provisions for Monitoring), §4.292 (relating to Minimum Permit Provisions for Closure), and §4.293 (relating to Permit Renewal).

The Commission also adopts new §4.301 (relating to Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings), and §4.302 (relating to Additional Permit Requirements for Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings) in new Division 7, Beneficial Use of Drill Cuttings.

Sections 4.203, 4.219, 4.232, 4.238, 4.248, 4.254, 4.264, 4.270, 4.272, 4.280, 4.286, 4.288, 4.301 and 4.302 are adopted with changes from the proposed text as published in the August 30, 2024, issue of the *Texas Register* (49 TexReg 6563). The remaining rules in Subchapter B are adopted without changes from the proposed text and will not be republished.

The Commission received 658 comments, 13 of which were from associations. The following associations submitted comments: Commission Shift, the Energy Workforce and Technology Council (Energy Workforce), the Panhandle Producers and Royalty Owners Association (PPROA), the Permian Basin Petroleum Association (PBPA), the Lone Star Chapter of the Sierra Club, the Texas Alliance of Energy Producers (Alliance), the Texas Bankers Association- Agricultural & Rural Affairs Committee (TBA), the Texas Farm Bureau (TFB), the Texas Independent Producers and Royalty Owners Association (TIPRO), Texas Industry Project (TIP), the Texas Land and Mineral Owners Association (TLMA), the Texas Oil and Gas Association (TXOGA), the Texas and Southwestern Cattle Raisers Association (TSCRA), and the Young Conservatives of Texas. Twenty-five companies or organizations also submitted comments. They include A.C.T. Operating Company (A.C.T.), American Energy Works, CrownQuest Operating, Inc. (CrownQuest), Deep Blue Midland Basin LLC (Deep Blue), Diamondback Energy (Diamondback), Dow Chemical Company, EPEC Energy, Fasken Oil and Ranch (Fasken), Galatea Technologies, Hance Scarborough, LLP, H&L Exploration, Mabee Ranch, Merit Energy Company (Merit Energy), Milestone Energy Services, Momentum Operating Co., Inc (Momentum), Northamerican Environmental Services, Inc. (NESCO), Pantera Energy Company (Pantera), Plains All American Pipeline, L.P., Recover USA, Inc., Stasney Well Service, LLC (Stasney), Texland Petroleum, United Environmental Services, LLC, Waste Control Specialists, Waste Management, Inc. (Waste Management), and Z&T Cattle Company. The remaining comments were submitted by individuals.

General Comments on Subchapter A

First, two comments requested that the Commission extend the effective date for the proposed new rules and amendments. Waste Management noted a later effective date would allow more time for training and communication on the new requirements, and Dow Chemical stated that facilities may need additional time to ensure compliance.

The Commission declines to extend the effective date further. The Commission specified in the proposal that the effective date for the rules would be July 1, 2025, which provides persons required to comply with the rules six months from adoption to prepare for compliance. Additionally, several rule provisions are adopted with a later effective date of one year or more from July 1, 2025. The Commission notes that due to comments on §4.192, the Commission adopts that section with changes, including a later effective date of December 31, 2026.

Similarly, Deep Blue Midland Basin (Deep Blue), Diamondback, TIPRO, and TXOGA requested clarification regarding whether the new rules and amendments apply retroactively to existing pits.

The Commission notes that §4.113 details how the Commission will treat pits authorized under §3.8, relating to Water Protection, prior to the adoption of Chapter 4. The Commission adopts amendments to §3.8 and other rules in Chapter 3 concurrently with the rules being adopted in Chapter 4.

American Energy Works and 152 individuals filed comments expressing general support for the rules because they prioritize businesses that fuel Texas's economy and create energy security. Sierra Club also expressed its support for the increase in transparency accomplished by consolidating waste management rules into Chapter 4. Sierra Club believes these rules take a step in the right direction but also noted several specific concerns with rules that do not go far enough, which are addressed in more detail below. The Commission appreciates the support expressed by these commenters.

In addition, the Young Conservatives of Texas and 152 individuals stated they support regulations which prioritize job creation, economic growth, and energy security. The commenters urged the Commission not to be persuaded by comments that would ultimately hamper job creation and affordable energy. The Commission appreciates the support of these commenters.

Two landowners and the Texas and Southwestern Cattle Raisers Association (TSCRA) commented in opposition to the rules proposed in Subchapter A. TSCRA stated that, overall, the proposed rules fail to adequately protect the safety of Texas's land and water. One landowner agreed. The other landowner asked the Commission to implement reasonable solutions to protect Texas landowners. The landowner noted experience with bad operators on her property and stated not all operators operate in good faith. She asked the Commission to ensure all pits are held to higher standards.

NESCO and Commission Shift commented in general opposition to the rulemaking. NESCO stated that Texas's waste management rules should be at least as stringent as those in Louisiana and New Mexico, but they fall short of that standard because they omit key environmental protections and contain technical deficiencies. Z&T Cattle Company also requested the Commission bring its rules closer into alignment with New Mexico's. Commission Shift believes the proposed rules do not adhere to statutory requirements. The Commission notes that the following organizations joined in Commission Shift's comments: Clean Water Action Texas, LaSalle County Commissioners Court, Liveable

Arlington, Lower Brazos Riverwatch, Middle Pecos Groundwater Conservation District, Reeves County Groundwater Conservation District, and River Pierce Foundation. Each time a comment from Commission Shift is addressed, these organizations are included in that reference.

The Mabee Ranch, TLMA, Commission Shift, NESCO, Gabriel Rio, Recover USA, and 34 individuals asked the Commission to reconsider protections proposed in its 2023 informal rule draft. The Mabee Ranch and one individual commented that the current draft places landowners and water resources at risk to appease a few smaller oil and gas operators and asked the Commission to instead consider the long-term consequences of the rules it proposed. Gabriel Rio, NESCO, and 15 individuals noted they can no longer support the rules due to changes made since the 2023 draft. They pointed to the lack of standards for pits used in the drilling process (i.e., reserve pits and mud circulation pits) as the glaring issue with the current proposal. Similarly, Recover USA stated the 2023 draft modernized regulations whereas the current proposal dilutes the requirements to the extent that it allows substandard disposal practices. Recover USA and one landowner commented that the Commission traded the balance it achieved in the 2023 draft for weaker regulations motivated by a few companies who argue cost is more important than environmental protection.

The Commission notes that these general comments are related to several comments submitted on specific rule provisions and includes its response to these comments in the Division 3 section below.

Several comments addressed the impact of the proposed regulations on small operators. Stasney Well Service, Momentum Operating, and H&L Exploration requested the Commission withdraw the proposed changes because unnecessary regulations cause economic harm- impacting jobs and rural communities. Specifically, Stasney Well Service and Momentum requested that the Commission recognize the differences in geology throughout Texas and apply the requirements of former §3.8 to operators of shallow vertical and/or stripper wells.

One landowner opposed the smaller operators' claim that they should be relieved from higher standards. She pointed to these operators' statements that they contribute a substantial portion to oil and gas production in Texas and concluded that due to the volume of their activity, it is unreasonable to exempt them from standards that would protect our environment. Three other landowners questioned the claims of smaller operators; specifically, the claim that the costs of compliance are too high. These landowners understand that additional costs will be incurred to comply with new standards, but noted the significantly higher costs incurred when harm to the environment occurs because no preventative measures are in place.

Milestone Environmental, Recover USA, and Commission Shift noted that updated pit regulations are not prohibitively costly and will not put small operators out of business. These comments noted that offsite burial or closed-loop systems are often the same cost or less expensive than onsite burial.

The Texas Bankers Association, the Energy Workforce and Technology Council, and 165 individuals recommended closed-loop systems be implemented in Texas. Energy Workforce also requested the Commission require other industry best practices such as emphasizing no uncontrolled releases, minimizing the environmental footprint of operations, and protecting groundwater through baseline sampling and advanced waste management systems.

The Commission notes that closed-loop drilling systems may be used in Texas and many operators use this method. The Commission does not typically endorse or mandate the use of certain technology. Rather, it allows operators to use technology they deem appropriate for their operations as long as their methods comply with the Commission's rules. Thus, the Commission declines to require closed-loop drilling systems in these rules.

Commission Shift, Sierra Club, and 57 individuals requested that the Commission create an electronic mailing list for all applications related to waste management and allow anyone to join the list. These commenters also requested that all pieces of an application file be kept online and made searchable for easy access by members of the public. The comments expressed opposition to allowing operators to retain information and only provide it upon request by the Commission.

The Commission is currently developing an update to its LoneSTAR online application to incorporate permit applications under Chapter 4. LoneSTAR will provide better access to application materials for the public.

The Texas Farm Bureau, TLMA, Texas Bankers Association, Mabee Ranch, Energy Workforce and Technology Council, Commission Shift, NESCO, TSCRA, Sierra Club, Z&T Cattle Company and 458 individuals commented requesting that the Commission incorporate some form of landowner notification or consent before an operator may conduct waste management activities, specifically disposal, on the property.

The Commission understands this concern but finds it does not have statutory authority to prevent authorization of waste management activities based on an applicant's failure to obtain landowner consent. Private contractual agreements and common law principles govern surface use of property associated with hydrocarbon production under a valid mineral lease. The Commission understands that the mineral lease and surface use agreements often address landowner notification and consent.

Commission Shift commented generally regarding proposed rules that allow the Director or District Director discretion to grant exceptions or consider alternatives to the rule requirements. Commission Shift opposes director discretion because it removes transparency. Commission Shift also commented that the proposed rules often place the burden on the public to prevent pollution and protect public health. Instead, the burden should be on the applicant to prove facilities are safe.

The Commission disagrees that the rules should be revised to remove director discretion. The Commission supports flexibility in the statewide rules that allow for consideration of unique facts or circumstances.

The Commission disagrees that the burden is on the public to prevent pollution. The burden is on the operator or applicant to conduct operations in accordance with the Commission's rules, which aim to prevent pollution and protect public health. Commission staff inspects facilities and also reviews information provided by operators and applicants to ensure facilities are in compliance.

Subchapter A, Division 1- General

Regarding §4.101, relating to Prevention of Pollution, Commission Shift commented that the Commission should expressly address pollution to land in addition to pollution to water. This is consistent with the definitions of "contaminant" and "pollution" in the Texas Natural Resources Code and the Texas Water Code.

The Commission declines to make any changes to §4.101 in response to this comment because the Texas Natural Resources Code explicitly references surface and subsurface waters. The Commission prefers to maintain consistency with the statutory language. Nevertheless, the Commission notes that action in response to crude oil spills under §3.91, relating to Cleanup of Soil Contaminated by a Crude Oil Spill, is required and the following rules also reference land or soil: §4.114(2)(A) for Schedule A pits, §4.132(b)(2)(D) for closure, §4.140(g)(1)(B) for commercial pits, §4.161(c)(5) for landfarming & landtreating, §4.241(c)(1) and (2) for design and construction, and §4.276(c)(5) and (d)(1) for closure. Section 3.91 is adopted with amendments in a concurrent rulemaking.

Commission Shift also commented regarding §4.101(c) and the use of the term "other wastes." Commission Shift asked that the Commission give examples of what types of waste are included in "other wastes" and specify how it will determine whether wastes are "physically similar to oil and gas wastes."

The Commission finds that "other wastes" may include wastes such as drilling fluids and drill cuttings when drilling a Class VI well for carbon sequestration and the wells that monitor the Class VI well. These drilling fluids and drill cuttings are similar in composition and volume to the drilling fluids and drill cuttings for oil and gas wells. These oil and gas waste drilling fluids and cutting wastes are disposed in landfarming operations.

Regarding §4.102, relating to Responsibility for Oil and Gas Wastes, Commission Shift requested the Commission require lab analysis rather than allow use of process knowledge for characterizing waste, especially when waste is generated at or will be transferred to a commercial facility. Commission Shift stated that process knowledge is not sufficient because it does not account for contaminants existing downhole or any constituents introduced during transfer.

Waste Management requested more guidance on what constitutes process knowledge and when lab testing is required. Waste Management also suggested the Commission require operators to retain documentation of process knowledge on site.

The Commission disagrees with Commission Shift that process knowledge is not sufficient for waste characterization. In most cases, process knowledge is sufficient to characterize a waste as an oil and gas waste and whether that waste is exempt from the Resource Conservation and Recovery Act (RCRA). The definition of "oil and gas waste" (from the §91.1011 of the Natural Resources Code and incorporated into §4.110(65)) is intrinsically defined based on the underlying process. That is, the term "means waste that arises out of or incident to..." and the statute lists a number of industrial processes that may generate waste. With regard to whether oil and gas waste is exempt from RCRA, the EPA provides this guidance document: "U.S. Envtl. Prot. Agency, Office of Solid Waste, EPA530-K-01-004, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations (2002)," which also describes a process knowledge approach to determining waste classification. Permit provisions may require or may require laboratory analysis of waste for waste generated at a commercial facility or when waste is transferred from one commercial facility to another, as stated in §4.102(a). Regarding Waste Management's comment requesting process knowledge documentation, the Commission notes that Section 4.190(b) requires a generator to document the waste characterization by completing a Waste Profile Form that documents the characteristics of each waste stream generated. This documentation is required to be kept for three years.

Regarding §4.102(e), Commission Shift requested clarification regarding the change from the 2023 informal rule draft, which used the phrase "any person who plans to utilize the services of a carrier or receiver is under a duty to determine that the carrier or receiver holds the appropriate authority from the Commission . . ." The current proposal changed subsection (e) to state, "any person *who utilizes*" rather than "*plans to utilize*." Commission Shift expressed concern that operators will use this change to avoid investigating whether a carrier has a permit.

The Commission disagrees. Section 4.102(b) provides sufficient clarity to address the concern expressed in the comment. It states, "No person, operator, generator, receiver, or carrier may utilize the services of a carrier to transport oil and gas wastes if the carrier is required to have a permit to transport such wastes but does not have a valid permit." However, the Commission considered this comment in review of other rules and adopts §4.203(c) with changes to clarify similar language.

TXOGA and Diamondback requested the Commission add §4.103(a)(4) to authorize without a permit the temporary storage of oil and gas waste by the generator at a nearby facility owned or operated by the generator. When pipelines generate waste during construction or maintenance, waste must currently be stored on the right of way, which creates a safety and security hazard. Allowing oil and gas waste generated on a third-party pipeline right of way to be transported and temporarily stored at the closest property owned by the generator will mitigate this hazard.

The Commission declines to make the requested change in §4.103(a)(4) because it notes the requested activity can be accomplished by following the requirements of §4.182 and obtaining a minor permit pursuant to that section. A waste hauler permit would still be required to move the waste.

Plains All American Pipeline also commented regarding §4.103. Plains All American stated that spills or releases in active remediation are appropriately regulated by strict adherence to §3.91 and do not need additional governance under §4.103. It suggested §4.103 be revised to reference §3.91.

The Commission agrees and adopts §4.103 with a change to reference §3.91 as recommended.

Dow Chemical Company submitted comments on §4.103 requesting clarification regarding whether the Commission considers waste management methods such as landfills and wastewater treatment to be authorized activities when the activities are regulated and/or permitted by the Texas Commission on Environmental Quality (TCEQ). Dow requested the Commission add language in §4.103(a) to address landfills and wastewater treatment facilities permitted by another state agency.

The Commission declines to adopt Dow's recommended changes in §4.103(a). The Commission notes that the waste management methods referred to in Dow's comments are already addressed by §4.103(e), which provides that some waste management methods are expressly governed by the Memorandum of Understanding (MOU) between the Commission and the TCEQ, which is found in §3.30. The MOU clarifies that waste management methods authorized by TCEQ include landfills and wastewater treatment. Relatedly, the disposal of trans-jurisdictional waste is addressed in §4.192 which is adopted with changes due to other comments as discussed further below.

Commission Shift requested clarification regarding changes to §4.103(b) made after the 2023 draft. The 2023 version prohibited "discharge of oil and gas wastes, geothermal resource waters, or other mineralized waters" unless certain exceptions applied. The newly proposed version removes reference to wastes other than oil and gas. Due to the change, Commission Shift questions whether subsection (b) applies to all waste under the Commission's jurisdiction, or only oil and gas waste.

The Commission agrees that §4.103(b) should reference all wastes under the Commission's jurisdiction and adopts §4.103(b) with that change.

Regarding §4.104, relating to Coordination between the Commission and Other Regulatory Agencies, Commission Shift requests that the Commission add a requirement for the applicant to provide the Commission with a copy of any authority required by a separate agency.

The Commission agrees that this information should be provided if requested by the Commission and adopts §4.104 with that change. The Commission notes that an operator may hold a valid TCEQ permit by rule even though it has not been acknowledged by the TCEQ. In that case, there may not be anything in writing to provide to the Commission. The Commission also notes that requests for authorization under a separate authority are currently considered when Commission staff evaluate permit applications. For example, if an application indicates co-mingling of contact and non-contact stormwaters or the application shows an outlet/valve for any discharge, the Commission asks the operator to produce a TPDES permit issued by TCEQ.

Commission Shift sought clarification regarding the distinction between an underground tank over which the Commission does not have jurisdiction and a pit regulated by the Commission.

The Commission notes that it does not have primary regulatory authority from the EPA for underground storage tanks defined in 40 Code of Federal Regulations (CFR) §280.12. This definition differs significantly from the definition for pit in §4.110(70).

Nine organizations and 57 individuals submitted comments related to §4.107, which contains the penalty guidelines for violations of Subchapter A.

Diamondback, TIPRO, and TXOGA requested the Commission add a good faith effort provision similar to the penalty guideline table in §3.66 of this title (relating to Weather Emergency Preparedness Standards).

The Commission declines to make the requested changes because good faith is already addressed by §4.107(i), which states, "In determining the total amount of any monetary penalty requested, recommended, or finally assessed in an enforcement action, the Commission may consider, on an individual case-by-case basis for each violation, the demonstrated good faith of the operator charged. Demonstrated good faith includes, but is not limited to, actions taken by the operator charged before the filing of an enforcement action to remedy, in whole or in part, a violation or to mitigate the consequences of a violation."

Commission Shift requested a revision to proposed §4.107(a) to recognize that voluntary corrective action *can be* an effective component of enforcement but is not always effective. Commission Shift also expressed support for the provision in proposed §4.107(b) in which the Commission reserves the right to automatically enforce violations. Commission Shift stated the Commission should also reserve the right to enforce a violation even after it has been corrected. This type of enforcement will deter future violations.

The Commission appreciates Commission Shift's support regarding §4.107(b). The Commission does not change the statement that encouraging operators to take "appropriate voluntary corrective and future protective action . . . *is* an effective component of the enforcement process." The Commission understands Commission Shift's concerns that this statement may be interpreted to mean that voluntary corrective action is the only method of enforcement. However, the statement is clear that corrective action is only one component of the enforcement process. The Commission finds the statement is accurate and needs no revisions.

The Texas Industry Project (TIP) expressed its opinion that a facility's history of compliance should not be held against a new operator if the operator did not operate the facility at the time of the prior violation.

The Commission agrees that a facility's history of compliance will not be held against a new operator because the operator is the one who receives the violation, not the facility.

Stasney Well Service and Momentum Operating commented that the penalty amounts proposed in §4.107 are too high, especially for smaller operators. They also requested that the Commission only assess penalties when actual harm occurs, not when pollution is merely threatened.

Conversely, Commission Shift noted that penalty amounts should not be considered as part of the fiscal impact for persons required to comply, including small businesses, because the costs are avoidable. Also, minimizing the impact on small operators or micro-businesses is not consistent with the statutory provisions authorizing penalties, which direct that penalties be punitive. Commission Shift requested that penalty amounts be increased. Commission Shift noted that penalties have not been increased since 2012 and, at a minimum, inflation should be taken into account in assessing whether the penalty amounts from §3.107 of this title (relating to Penalty Guidelines for Oil and Gas Violations) are appropriately incorporated into Chapter 4.

Relatedly, the Texas Farm Bureau asked that penalty amounts be increased when operators submit inadequate or false data, especially for operators of authorized pits. The comments noted that these violations should be strictly enforced because the operators will avoid most regulatory requirements and should at least provide accurate registration information.

Sierra Club asked that the Commission narrow the penalty ranges and clarify that penalties are assessed per violation, per day and not as a one-time fine.

Regarding the comments on penalty amounts from Stasney Well Service, Momentum, Commission Shift, the Texas Farm Bureau, and Sierra Club, the Commission notes the penalties are merely guidelines. The actual penalties recommended and assessed will be determined by the Enforcement Section of the Office of General Counsel, the Administrative Law Judge and Technical Examiner in the Hearings Division, and ultimately, the Commissioners.

The Commission agrees with Sierra Club's comment that the Commission is authorized to assess penalties up to $10,000 a day for each violation. Texas Natural Resources Code §81.0531(b) provides that authority and states, "Each day a violation continues may be considered a separate violation for purposes of penalty enforcement." The authority provided by this statute provides the Commission sufficient flexibility to assess significant penalties when necessary. Thus, the Commission declines to make changes to increase the guideline penalty amounts.

Commission Shift and 57 individuals requested the Commission improve enforcement generally. They argued that the Commission's existing rules are not well-enforced and the penalties do not effectively deter bad actors.

The Commission notes that the 88th legislature provided the Commission funding for a "compliance team" to be established in the Environmental Permits Unit. Since its inception, this team has reviewed quarterly reports in a timely fashion, conducted inspections of permitted facilities, and increased the number of violation letters and enforcement actions initiated by staff.

Commission Shift requested the table in §4.107 be revised to include the following additional rule violations: failure to register an authorized pit within the time limit prescribed, failure to construct an authorized pit in accordance with requirements in Division 3, failure to close an authorized pit (including flare pits and basic sediment pits) in accordance with Division 3, failure to report discrepancies as required by §4.194(b), failure to maintain records for at least three years as required by §§4.194 and 4.195, and failure to comply with the rules in Subchapter B, Division 7.

The Commission declines to add the requested rule violations to the table because the items in the table are merely example penalty guidelines. The table does not contain the universe of possible violations.

Subchapter A, Division 2- Definitions

TXOGA and Diamondback noted that the term "drilling fluids" is used in the proposed rules but is not defined. These commenters recommended the term be defined as "all non-hazardous, low-chloride liquids and drilling mud associated with drilling activities for oil and gas exploration, development, and production activities."

The Commission agrees that a definition for drilling fluid should be added and adopts §4.110 to include the term, which the Commission defines as "any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill boreholes into the earth."

Commission Shift suggested the Commission require operators to submit a Construction Quality Control form and define the term Construction Quality Control to ensure permitted operations are constructed properly. Commission Shift proposed the following definition for Construction Quality Control: A planned system of inspections that is used to directly monitor and control the quality of a construction project. Construction quality control is normally performed by the geosynthetics installer and is necessary to achieve quality in the constructed or installed system. Construction quality control (CQC) refers to measures taken by the installer or contractor to determine compliance with the requirements for materials and workmanship as stated in the plans and specifications for the project.

The Commission declines to adopt this recommendation. Section 4.124(e)(3)(A) provides that all geotechnical testing shall be performed by a laboratory certified to conduct geotechnical testing according to the standards specified by the American Society of Testing and Materials (ASTM) and certified by a professional engineer licensed in Texas. And, in many cases throughout the rule (especially for liners), the rules require adherence to manufacturer's instructions for installation and maintenance.

Regarding the term 100-year flood, Commission Shift requested that the Commission remove the phrase "significantly long period" or clarify what the phrase means.

The Commission agrees and adopts the recommended change in §4.110.

Regarding the term 100-year flood plain, TXOGA and Diamondback asked for clarification regarding whether the requirements apply in areas where maps do not exist. Commission Shift requested that references in the definition to the U.S. Army Corps of Engineers be removed because the Federal Emergency Management Agency (FEMA) is the primary authority for flood plain data.

The Commission disagrees with TXOGA and Diamondback. Even when maps are not available, the operator should be aware of the surface hydrology potential of a location. The Commission also declines to remove the reference to the U.S. Army Corps of Engineers because some areas of Texas have not been mapped by FEMA such that 100-year flood plains are identified.

Deep Blue, Diamondback, TXOGA, and Commission Shift commented on the proposed definition of "action leakage rate." Deep Blue, Diamondback, and TXOGA requested clarification that a leak is only an indication of a possible failure. Commission Shift requested changes to require an operator to find the cause of liner failure and repair the liner when the action leakage rate indicates severe failure of the primary liner.

The Commission declines to make changes to the definition of action leakage rate based on these comments. The Commission finds that exceeding the action leakage rate indicates a system failure until proven otherwise. The Commission also determines it is not appropriate to include requirements in the definition, such as the suggested requirement to find the cause of the failure and repair the liner.

Commission Shift requested that the Commission revise the definition of "affected person" to specify that the term includes surface owners, groundwater conservation districts, and residents within one mile of the facility's property boundary. The comment stated the change would assist the public in understanding who is affected.

The Commission declines to make the requested change. The rule does not limit the definition of an "affected person" to one who is explicitly entitled to notice. Instead, the definition provides flexibility because affected person status is only based on whether the individual has suffered or may suffer actual harm.

Commission Shift commented that the term "alluvium and quaternary sand and gravel" should be removed from §4.110 because the term is not used in Chapter 4.

The Commission agrees and removes the term from §4.110.

Commission Shift asked that the Commission revise the definition of aquifer because the Commission should ensure protection of all subsurface water, not just aquifers capable of yielding significant quantities of groundwater.

The Commission declines to make any changes to the proposed definition of aquifer. The Commission's pollution standard is for no pollution of "surface or subsurface waters." An "aquifer" is a type of subsurface water. Defining aquifer as a geological formation, group of formations, or portion of a formation capable of yielding significant quantities of groundwater to wells or springs does not limit or otherwise impact the Commission's protection of subsurface water. "Surface and subsurface water" are also defined and referenced in these rules.

Regarding the proposed definition of "authorized," Commission Shift requested clarification because the definition includes the term "permitted," which has a common meaning and a meaning under the Commission's rules. Thus, clarification regarding what the term means in the definition of "authorized" would be beneficial.

The Commission agrees that the proposed definition of "authorized" could create confusion. The term "authorized" when used in Subchapter A generally refers to a permit-by-rule approval such that the activity is allowed by the rule and the operator is not required to apply for and obtain a permit.

Several comments were submitted regarding the Commission's proposed definition of "commercial facility." The Alliance, American Energy Works, Deep Blue, Diamondback, Pantera Energy Company, PBPA, PPROA, TIP, and TIPRO commented requesting clarification and suggesting edits relating to how operator controlled/owned produced water recycling facilities will be regulated. These commenters expressed concern that produced water recycling facilities would be considered commercial when a parent company uses subsidiaries to operate water management aspects of its business.

The Commission notes that the definition of commercial facility states that a commercial facility is a facility permitted under Division 4 of Subchapter A. The other language in the definition ("whose owner or operator receives compensation from others for the management of oil field fluids or oil and gas wastes and whose primary business purpose is to provide these services for compensation") only applies to facilities that meet the first part of the definition - those that are permitted under Division 4 of Subchapter A. Produced water recycling pits are authorized under Division 3 of Subchapter A so they are not considered commercial facilities under Subchapter A's requirements.

Commission Shift asked for revisions to clarify that waste management units located at commercial facilities must be included in the permit rather than authorized by rule.

The Commission declines to revise the definition of "commercial facility" in accordance with Commission Shift's suggestions but confirms that any waste management unit located on the same property as a commercial facility is required to be permitted. For example, a pit that is used for produced water recycling and is located at a commercial waste facility would be permitted and would be included on the commercial facility's permit. The Commission adopts §4.120 with a change to clarify this requirement.

The Alliance, American Energy Works, Pantera Energy, PBPA, PPROA, TXOGA, and TIP commented that the proposed definition of contact stormwater is too broad and should be revised to ensure operators are not required to manage water that has not come into contact with oil and gas waste. TXOGA and TIP noted that the proposed definition may encompass stormwater at facilities not yet commissioned.

Commission Shift expressed support for the proposed definition and recommended two minor edits to encompass stormwater at authorized facilities.

The Commission agrees that operators should not be required to manage water that has not come into contact with oil and gas waste or with areas that have contained oil and gas waste. The Commission adopts the definition of "contact stormwater" with changes to address these comments. The Commission defines contact stormwater as stormwater that has come into contact with any amount of oil and gas wastes or areas that contain or have contained oil and gas wastes. The Commission also adopts the definition of "non-contact stormwater" with changes to clarify that all stormwater is either contact or non-contact. The definition of stormwater will be adopted without changes.

One individual suggested that the Commission ensure consistency when using the term stormwater to ensure it is always one word rather than two (i.e., stormwater rather than storm water). The Commission agrees and makes minor changes throughout the rules to ensure consistent use of the term.

NESCO recommended that the paint filter test be referenced in the definition of "dewater." The Commission agrees and adopts §4.110 with a revised definition of dewater.

Relatedly, Commission Shift recommended that the Commission define the term "free liquids," which the used within the proposed definition of "dewater." The Commission agrees and adopts §4.110 with changes to add a definition of "free liquids" as §4.110(39).

Regarding the proposed definition of "disposal," Plains All American asked that the Commission clarify how the term, and regulation of disposal under Chapter 4 in general, relates to spills that are in active remediation in accordance with §3.91 (relating to Cleanup of Soil Contaminated by a Crude Oil Spill). Plains recommended the definition of disposal expressly exclude a spill or release that is addressed under the requirements of §3.91.

The Commission agrees that disposal does not include a spill or release handled in accordance with §3.91. However, the Commission declines to amend the definition of disposal. Instead, the Commission adopts §4.103(a) with a revision stating that unless authorized by Subchapter A, no person may manage oil and gas wastes without obtaining a permit to manage such wastes, except for certain methods listed in subsection (a) including methods authorized by §3.91.

Diamondback and TXOGA requested that the proposed definition of drill cuttings be revised to encompass wells that are not oil and gas wells.

The Commission agrees and adopts the definition with a change to include other wells within the Commission's jurisdiction.

Regarding the proposed definition of "freeboard" NESCO and Commission Shift asked the Commission to revise the definition to ensure freeboard includes sufficient storage capacity to contain rainfall from a 25-year, 24-hour rainfall event.

The Commission disagrees that the standard suggested by NESCO and Commission Shift should be added in the definition. Freeboard is the measurement of the vertical distance between the top of a pit or berm and the highest point of the contents of the pit or berm. The required amount of freeboard is established in the rules, which require two feet of freeboard plus capacity to contain the volume of precipitation from a 25-year, 24-hour rainfall event.

The Commission received several comments about the proposed definition and concept of fresh makeup water pit. CrownQuest commented that the Commission should not regulate use or management of true fresh water. Merit Energy requested a new definition and requirements for fresh makeup water pits to allow operators to manage the total dissolved solids in the pit and continue operating as long as the water contained in the pit does not have constituents in concentrations exceeding those of groundwater in the area.

The Alliance, Deep Blue, Diamondback, Pantera Energy, PBPA, PPROA, TIP, TIPRO, and TXOGA noted that industry is working to reduce its fresh water use by sourcing water from brackish or saline aquifers. However, the proposed definition and regulation of fresh makeup water pit would discourage the use of alternative water sources. The commenters suggested that the term "fresh makeup water pit" be replaced with "makeup water pit." Merit Energy and Fasken Oil and Ranch also commented supporting a new definition and concept of "makeup water pit."

The Commission agrees and replaces "fresh makeup water pit" with "makeup water pit," which is adopted as §4.110(55). The Commission also incorporates the new pit type into §4.114, which is discussed in more detail in the "Subchapter A, Division 3- Operations Authorized by Rule" section below.

Deep Blue, Diamondback, Stasney Well Service, TIPRO, and TXOGA submitted comments regarding the proposed definition of "fresh water." Diamondback, TIPRO, and TXOGA asked that the Commission remove the definition's one-mile radius component, which would require additional research to determine what constitutes fresh water in a certain area. Deep Blue requested a straightforward definition that would provide clarity and reduce regulatory requirements. Deep Blue noted its concerns related to the impact of the definition of fresh water in the regulation of fresh makeup water pits. Stasney Well Service suggested the Commission define fresh water as water with less than 1,000 mg/l total dissolved solids (TDS) and add a definition of usable quality water, which would be defined as water with 3,000 mg/l TDS or less.

The Commission determines that due to changes relating to the removal of "fresh makeup water pits" and the creation of the new "makeup water pit" type, the definition of "fresh water" is no longer necessary. The Commission removes that term in the adopted version of §4.110.

Regarding the proposed definition of geomembrane, Commission Shift suggested the Commission revise the definition to remove "effectively" from the phrase "effectively impermeable" because the use of "effectively" may create a loophole for compliance.

The Commission adopts §4.110(43) with a change to remove "effectively" as suggested.

The Commission received eight comments related to the proposed definition of "groundwater." The Alliance, Diamondback, Pantera Energy, PBPA, and TXOGA asked that the definition specify that groundwater is subsurface water *in a confined or unconfined aquifer*.

The Commission declines to adopt the requested change. The definition states that groundwater is subsurface water in a zone of saturation. The Commission finds this definition easier to apply.

The Alliance, American Energy Works, EPEC Energy, PBPA, and PPROA also requested clarification regarding whether the definition of groundwater includes produced water.

The Commission does not consider groundwater to include produced water. Water that is present in a subsurface formation coincident with hydrocarbons is groundwater. When the coincident groundwater is produced with hydrocarbons, it becomes produced water, which is currently considered an oil and gas waste under Texas Natural Resources Code §91.1011, and the corresponding Commission rule §4.110(65). The Commission adopts §4.110 with a definition of "produced water" to help clarify this issue.

Stasney Well Service suggested the Commission define groundwater as "usable quality groundwater" because Commission-regulated operators are familiar with that term. Commission Shift requested that the definition include any water under the surface of the ground (both aquifers and subsurface water) regardless of quality.

The Commission declines to make changes due to these comments. The adopted definition, which defines groundwater as subsurface water in a zone of saturation, references subsurface water. Subsurface water is defined in §4.110 and includes all subsurface water regardless of quality.

Stasney Well Service and Momentum Operating asked the Commission to add a definition for hazardous oil and gas wastes.

The Commission declines to adopt a definition of hazardous waste. The Commission's regulations in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste) describe oil and gas wastes that are hazardous and govern management of these wastes. The Commission adopts §4.102 with changes to clarify that hazardous oil and gas waste must be managed pursuant to §3.98.

Regarding the proposed definitions of landfarming and landtreating, NESCO stated the two activities are not the same and should not be regulated as such. Landfarming should be applied only to disposal of oil and gas wastes at the well site, well location, or lease whereas land treatment is applicable to treatment and disposal at a commercial disposal facility. It is a dynamic process involving the controlled application of E&P waste onto or into the aerobic surface soil horizon in open cells by a commercial land treatment facility accompanied by continued monitoring and management to alter the chemical state of the waste. Commission Shift agreed regarding the definition of landtreating and suggested the definition of landtreating be revised to ensure the treatment process is included. NESCO also commented that landtreating is an incorrect term and the Commission should revise it throughout Subchapter A to refer to land treatment instead.

The Commission declines to change the term landtreating and also declines to change how it regulates these two activities. For several years, the Commission has applied the term "landfarming" to the integration of low-chloride water-based drilling fluids and cuttings into a soil horizon, and applied the term "landtreatment" (or "landtreating") to the similar management of oil-based drilling fluids in which bioremediation occurs. The Commission will continue this practice. The Commission agrees that the definition of landtreating should be revised to reference the treatment process and adopts the definition with those changes in §4.110(52). In addition, the Commission notes that in the past its Surface Waste Management Manual has provided guidance on the practices of landfarming and landtreating as well as other waste management activities. The Commission will update the manual to reflect these new rules, including the new definition of landtreating.

Diamondback and TXOGA also commented on the proposed definition of landfarming. They recommended the Commission use the term "water-based drill cuttings" rather than "water-based drilling fluids" because the fluids should be addressed under land application, in which the fluids penetrate into the soil such that tilling or mixing into the soil by landfarming is not necessary. Stasney Well Service commented that tilling is not always possible or practicable due to native soil and plant life and asked the Commission to include burial as an accepted practice under the definition of landfarming.

The Commission disagrees with these commenters because both drilling fluids and drill cuttings can be landfarmed and burial is only authorized for certain wastes pursuant to §4.111. Landfarming and landtreating are different from burial- they include integration of the waste into the surficial soil horizon.

Diamondback and TXOGA commented regarding the proposed definition of land application. They suggested the Commission remove the reference to produced water and add "water-based drilling fluids." They noted water-based drilling fluids is referenced in the definition of landfarming and there are other Commission-regulated activities that would meet the criteria of being a low-chloride water fluid that is not a "produced water," such as de-watering of hydro-excavated soils or dewatered drilling mud. Therefore, replacing "produced water" with "water-based drilling fluid" will maintain the intent of the definition without limiting the scope to only well-sites.

The Commission adopts §4.110(49) with a change to address this comment. Land application will be defined as a method for the permanent disposition of low-chloride aqueous oil and gas waste by which the liquid waste is applied directly to the ground surface in a controlled manner via sprinkler or other irrigation systems without tilling or mixing with the native soils and without runoff to surface water or infiltration to groundwater.

Commission Shift requested clarification regarding changes to the definition of "natural gas or natural gas liquids processing plant" and asked whether the changes will impact regulation of these plants. The Commission notes that the proposed definition intends to clarify that waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants are under the jurisdiction of the Commission, except natural gas liquids processing plant waste that is hazardous. The new definition does not impact the regulation of these plants. Rather it combines the statement from §3.1(a)(1)(D) of this title (relating to Organization Report; Retention of Records; Notice Requirements) that recognizes the Commission's jurisdiction over natural gas treatment or natural gas liquids processing plants with the concept from §3.98 that oil and gas waste excludes hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants.

Commission Shift, PBPA, and TXOGA suggested revisions to the proposed definition of "operator." These commenters focused on the list of activities referenced in the definition (e.g., permitting, physical operation, and closure) and either commented that the list was too specific or should include more activities.

The Commission understands that the list may create more questions than it resolves and so the Commission adopts the definition of "operator" with a change to ensure consistency with the definition in §3.79 of this title (relating to Definitions). The revised definition removes the list of activities and instead defines operator as a person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the Commission's rules and regulations in any acts subject to the Commission's jurisdiction.

Stasney Well Service requested revisions to the proposed definition of "pollution" to incorporate the concept of usable quality water and to state that pollution does not include nonhazardous oil and gas wastes exempt from the Resource Conservation and Recovery Act (RCRA).

The Commission disagrees. The proposed definition of pollution is consistent with the statutory definition in the Texas Water Code, Chapter 26.

Stasney Well Service and Momentum Operating requested that the Commission add a definition of process knowledge and Stasney provided the following proposed definition: Process knowledge is the combination of skills, understanding, experience, and expertise of an average oil and gas operator in a given geographic area concerning a given type of material, waste, well, or oil field operation.

The Commission disagrees with the language proposed by Stasney because the characterization of waste is a technical determination and the definition proposed by Stasney does not incorporate any specialized knowledge or analysis. The Commission notes that its position on process knowledge is addressed above in the "Subchapter A, Division 1- General" section in the paragraph discussing §4.102.

The Commission received comments on the definition of "produced water recycling facility." However, the Commission notes that term is no longer used in the rules so it is removed from §4.110.

Regarding the proposed definition of "public area" Commission Shift requested clarification regarding whether the Commission interprets a day care to be a public area.

The Commission interprets "public area" to include a day care because the definition includes "school" as well as "place of business."

The Alliance, American Energy Works, Deep Blue, Diamondback, Fasken Oil and Ranch, Pantera Energy, PBPA, PPROA, TIP, TIPRO, TXOGA and Waste Management also commented on the proposed definition of "public area." The Alliance, American Energy Works, Diamondback, Pantera Energy, PBPA, TIP, and TXOGA requested that the Commission remove the reference in the definition to a public road because including public road makes the definition of "public area" overly broad and will unnecessarily restrain siting of operations. Relatedly, Deep Blue, TIPRO, and Waste Management recommended that the Commission reference §3.36 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) rather than incorporating the definition of public area into Chapter 4. These commenters stated that §3.36 is more comprehensive in addressing safety concerns related to hydrogen sulfide.

The Commission agrees that including "public road" may overly restrict siting and agrees to remove that term from the definition. The Commission disagrees with Deep Blue, TIPRO, and Waste Management regarding referencing §3.36 rather than defining "public area" in Chapter 4. The Commission incorporated the definition from §3.36 because Chapter 4 has siting requirements based on distance to public areas and defining the term is helpful for providing clarity. In Chapter 4, the definition of public area is unrelated to whether hydrogen sulfide requirements are implicated. Rather, it was incorporated because it is an established definition with which both the regulated industry and Commission staff are familiar.

TXOGA and Diamondback requested that the word "permit" be removed from the proposed definition of "recyclable product" in §4.110 because the term can apply in both authorized activities and activities for which an operator must obtain a permit.

The Commission agrees and adopts the definition of "recyclable product" with the requested change.

Waste Management asked that the Commission revise the definition of "secondary containment" to match the definition included in TCEQ's rules.

The Commission declines to make the requested change because it would create inconsistency in the structure and content of the Commission's rules. The Commission uses "primary containment" and "secondary containment" to describe the relationship between a container that performs the function of primary containment, and secondary containment which is intended to mitigate the damage from spills.

Regarding the proposed definition of "surface and subsurface water," Stasney Well Service commented that surface water should be the focus of this rule. The catch-all phrase "all other bodies of surface water, natural or artificial" is too broad and is subject to unlimited interpretations.

The Commission disagrees. Commission rules are consistent with applicable statutes, which are broadly protective of surface and subsurface waters of the state.

The final definition proposed in §4.110 is "wetland." Commission Shift commented that the Commission should include a reference to NWI maps and presume the existence of a wetland if so indicated by an NWI map unless an onsite wetlands determination by a wetlands expert concludes otherwise.

The Commission declines to adopt the definition with the suggested change because the proposed definition matches the definition in Texas Water Code §11.502. The Commission notes that it uses National Wetlands Inventory (NWI) when evaluating permit applications.

Subchapter A, Division 3- Operations Authorized by Rule

Commission Shift commented generally regarding activities authorized under Division 3 that are located on the same site as a facility permitted under Division 4. Commission Shift stated that once a waste management unit on a facility requires a permit, then every waste management unit on the facility should be described in and covered by the permit, even if those activities are typically authorized under Division 3.

The Commission agrees and adopts §4.120(b) with changes to clarify this issue.

Commission Shift and Stasney Well Service also commented generally regarding the record-keeping requirements of Division 3. Commission Shift suggested that instead of three years, all documentation should be required to be retained permanently. Commission Shift also suggested that all construction, sampling, and closure documents be shared with the surface owner.

Stasney asked that pits with less than 50 barrels of waste be exempt from documentation requirements. Stasney also requested clarification regarding what types of documentation is required to be maintained.

The Commission disagrees that low volume pits should be exempt from maintaining documentation. The documentation required is documentation necessary to support compliance with Commission regulations. Regarding Commission Shift's comments, the Commission notes that the registration information will be maintained by the Commission through its online registration system, which will have a different retention timeframe than the operator's three-year requirement.

Regarding §4.111(a) which addresses land application of water condensate, Commission Shift requested that additional parameters be included in the Figure proposed in subsection (a). Commission Shift requests the Commission add testing for TPHs, BTEX, and replace chloride concentration with TDS or electrical conductivity.

The Commission disagrees that the constituents requested by Commission Shift are appropriate for water condensate, the material to which the Figure applies. The proposed constituents are sufficient and appropriate for water condensate.

Diamondback and TXOGA commented regarding §4.111(c)(10), which authorizes disposal of certain oil and gas wastes by landfarming and requested that the requirement in subsection (c)(10) be revised to take background levels into account.

The Commission declines to provide for background concentrations of total petroleum hydrocarbon content (TPH) in soil because the standard in subsection (c)(10) is 1% or less by weight.

Relatedly, Commission Shift commented that testing should be required prior to the application of waste under §4.111.

The Commission notes that because §4.111(c)(9) requires the waste-soil mixture to have "an electrical conductivity that does not exceed the background level for undisturbed soil before landfarm activities commence," the operator would need to establish background soil constituent concentrations prior to the landfarming activity.

Stasney Well Service asked that §4.111 be expanded to allow burial of nonhazardous oil and gas waste in place.

The Commission declines to expand §4.111. The section allows for limited on-lease disposal of certain oil and gas wastes generated on the lease.

Diamondback, TXOGA, and PBPA commented regarding §4.112, which relates to Authorized Recycling. These commenters requested changes to the rule so that it contemplates fluids that do not need to be treated to be recycled.

The Commission agrees that produced water used down the wellbore may be treated but is not required to be treated prior to being used in the wellbore and the Commission adopts §4.112 with a change to clarify that issue. All other recycling of liquid oil and gas waste requires a permit, either under Division 4 of Subchapter A, or under Subchapter B.

Commission Shift asked that the Commission expressly prohibit pooling of produced water from multiple leases without a permit.

The Commission disagrees. The commingling of produced water into water management pipeline and pit networks has become an essential element of oil and gas operations across the state. Such commingling is necessary to "encourage fluid oil and gas waste recycling," which is a state policy established in Natural Resources Code Chapter 122.

Regarding §4.112, Commission Shift also requested clarification regarding when produced water recycling pits are regulated under Subchapter A and when they are regulated under Subchapter B.

The Commission considers the only authorized method to recycle produced water is to use the produced water in a downhole operation. This position is consistent with the Commission's application of the requirements of the prior version of §3.8. All other recycling of liquid oil and gas waste requires a permit, either under Division 4 of Subchapter A, or under Subchapter B.

TETRA Technologies requested clarification regarding standards in §3.8 ("Rule 8") that were not incorporated into the current proposal. Rule 8 authorized recycling of treated fluid resulting in distilled water and did not require a permit for use of the resulting distilled water. That activity is not authorized in the current proposal, which limits companies like TETRA from directing R&D activities toward exploring opportunities for reuse of produced water recycled to that level of purity.

The Commission finds that §3.8's blanket authorization to allow distilled water to be reused for any purpose is now imprudent due to the recent attention to the development of technology and logistics to treat and recycle produced water, some of which include unproven distillation methods and processes. Because the term "distilled water" is no longer used in these rules, the Commission adopts §4.110 with a change to remove that term.

The Commission received a number of comments regarding §4.113, which addresses authorized pits. Section 4.113(b) requires all authorized pits to be constructed, used, operated, and maintained at all times outside of a 100-year flood plain unless the District Director grants an exception after a showing that the contents of the pit will be confined in the pit at all times.

CrownQuest stated that the requirement for authorized pits to be constructed outside the 100-year flood plain makes sense for produced water pits or other pits that will operate for several years, but not for temporary reserve pits. CrownQuest stated this requirement massively increases costs and significantly affects the availability of pit locations.

The Commission disagrees. The prohibition on siting an authorized pit in a 100-year flood plain has been in §3.8 for many years. The Commission notes an operator may receive an exception.

As referenced in the general comments section above, Commission Shift opposes any provision that provides the Director or District Director with discretion to approve exceptions. Commission Shift commented in opposition to the proposed exception in §4.113(b) as well.

The Commission disagrees. The Commission supports flexibility in the statewide rules that allow for consideration of unique facts or circumstances. Discretion is not limitless. An exception may only be granted upon a showing that the contents of the pit will be confined to the pit at all times.

Section 4.113(c) contains instructions and requirements for authorized pits constructed pursuant to and compliant with §3.8 ("Rule 8") as that rule existed prior to July 1, 2025.

Commission Shift stated that existing pits should be required to come into compliance with all new rules, and should not be limited to complying with the new rules at closure only. Commission Shift recommended that subsection (c)(1) should be revised to require all existing authorized pits to come into compliance with Division 3, not just those authorized pits that cause pollution.

The Commission notes that pursuant to §4.113(c)(3), a pit considered a non-commercial fluid recycling pit under prior §3.8 is required to register as a produced water recycling pit and submit the required financial security. Regarding other pits coming into compliance with the new rules, the Commission declines to make changes to §4.113 based on this comment, but notes that the other authorized pits generally have shorter operational lives. Thus, the Commission anticipates the pits will be closed due to inactivity and the normal course of operations. Closure must be accomplished in accordance with the new rules.

The Alliance, American Energy Works, Deep Blue, Diamondback, Pantera Energy, PBPA, PPROA, TIPRO, and TXOGA requested revisions to §4.113(c)(1) to remove the reference to pits authorized under §3.8 that cause pollution and merely require authorized pits to be in compliance. The commenters note the statement that authorized pits that cause pollution shall be brought into compliance or closed would mandate the operator to conduct a site assessment to demonstrate pollution is not occurring, which requires proving a negative.

The Commission declines to adopt the suggested changes. Section 4.113(c) already addresses the importance of compliance. The purpose of §4.113(c)(1) is to address any pollution stringently.

The Commission received several general comments about authorized pits addressed in §4.113, §4.114, and §4.115. First, TLMA, the Mabee Ranch, Z&T Cattle Company, and Commission Shift commented that all types of pits should have the same standards for construction, operation, and closure due to their potential impact on the environment. One individual specifically requested that groundwater monitoring requirements be imposed for all pits. The Texas Bankers Association, NESCO, Commission Shift, and 74 individuals asked the Commission to require liners, leak detection, and groundwater monitoring for Schedule A pits similar to standards for commercial operations.

Commission Shift also stated that the Commission has no rational basis for imposing so few requirements for Schedule A pits and asked that the Commission set more protective rules for Schedule A pits in order to prevent pollution. Further, at the beginning of this comment summary, the Commission noted several sets of comments expressing opposition to the proposed new rules and amendments because the commenters believe the rules fail to adequately prevent pollution or adequately protect the safety of Texas's land and water.

The Commission adopts §4.114 with changes to address some of these concerns, as discussed in more detail below. However, at the outset, the Commission argues that this rulemaking marks a significant effort on the part of Commission and the industry to update our cornerstone rules for environmental protection and pollution prevention. These rules incorporate many of the current best practices employed by industry for authorized pits. For example, authorized pits that contain fluids with more than 3,000 mg/l total dissolved solids (TDS) must be lined, as must authorized pits whose pit bottoms are located within 50 feet of groundwater. In addition, because of the industry's expanding use of recycled produced water, and the proliferation of associated very large pits, produced water recycling pits have been identified as a special category of authorized pits. Operators will be required to post a financial security bond to enable the Commission to fund pit closure, if needed. Further, many of the standard permit conditions that are currently issued for permitted facilities have been incorporated into the rules. For example, the need for and manner of conducting groundwater monitoring to prevent pollution has been incorporated into the rules. The Commission has also created a Compliance Team that is responsible for ensuring waste facilities are compliant with the statewide rules and individual permits. Together--more specific rule requirements and a dedicated compliance team--will enable the Commission to meet its statutory obligations to the people of Texas.

Regarding the regulation of Schedule A and Schedule B pits, the Commission concludes that Schedule A pits, which are designed for short-term use, present a lower risk than pits that are used for longer periods of time. Thus, the Commission adopts the rules relating to Schedule A pits with fewer requirements than Schedule B pits.

Regarding the categorization of pits as either Schedule A or Schedule B, Texland Petroleum and A.C.T. support how the proposal classified pits, commenting that the approach is a commonsense method for regulating different types of pits and that the regulations for each type are reasonable.

The Commission appreciates these comments.

The Texas and Southwestern Cattle Raisers Association commented that use of authorized pits should be rare, and when they are utilized, they should be closed as soon as possible and be required to undergo continued monitoring and oversight.

The Commission disagrees that use of authorized pits should be rare. By design, authorized pits are commonly built, used, and closed at active oil and gas exploration and production sites. It is because most of these pits have shorter temporal lives and are smaller in size that the Commission imposes fewer requirements for their operation.

Regarding how to categorize pits and apply requirements applicable to each pit type, NESCO commented that the Commission should separate non-commercial and commercial facilities (i.e., focus on difference in quantity of waste, the size of the facility, and the difference in duration of operation). The rules for commercial facilities that are larger in size and volume and operate longer should reflect the threat they pose. EPEC Energy also commented that the Commission should consider the size of the pit and noted that larger pits with higher toxicity contents or pits that will keep waste for a long time should be Schedule B.

The Commission notes that all authorized pits are non-commercial under the definitions adopted in §4.110. Generally, the distinction between Schedule A and Schedule B pits does incorporate an aspect of pit size and duration of operational life. Schedule A pits are generally smaller and have shorter operational lives than Schedule B pits. As discussed below, the Commission also adopts §4.114 with changes to impose liner requirements for pits with higher total dissolved solids contents.

Section 4.113 provides that the following pits are considered Schedule A authorized pits: reserve pits, mud circulation pits, completion/workover pits, makeup water pits, fresh mining water pits, and water condensate pits. The pits are authorized without a permit only if they comply with the requirements of §4.113 and §4.114.

Commission Shift asked that the list of Schedule A pits be exclusive, so the rules are clear regarding which types of pits are authorized and which requirements apply.

The Commission agrees and finds §4.113(a) is worded such that only the pits listed in that subsection are considered Schedule A pits. However, proposed §4.114 states, "Schedule A authorized pits *include* reserve pits, mud circulation pits, completion/workover pits, freshwater makeup pits, fresh mining water pits, and water condensate pits." The Commission adopts §4.114 with a change to make this list exclusive in accordance with Commission Shift's comment.

Regarding proposed subsection (d) of §4.113, relating to unauthorized releases from authorized pits, Diamondback, TXOGA, and TIP requested that the Commission establish a reportable quantity for spills from authorized pits or reference existing §3.91.

The Commission declines to make the requested change. Section 3.91 relates to crude oil only, not oil and gas waste. The Commission has traditionally viewed spills of waste or other materials, which are not addressed in §3.91, to be "unauthorized or improper disposal" pursuant to the requirements of §3.8 effective prior to the adoption of these rules. The Commission will continue this approach and expects that waste spills will be managed on a case-by-case basis with coordination as needed from the District Office and Technical Permitting.

Section 4.113(e) requires registration of all authorized pits. The Texas Farm Bureau expressed support for the registration requirements but asked that the Commission specify how frequent it will perform inspections. The Bureau requested at least annual inspections.

The Commission appreciates the Bureau's support. The inspection schedule will be set by the district offices based on activity in each district. Most drilling locations are inspected when active and because most authorized pits are at active drilling locations, they will be inspected routinely.

Fasken Oil and Ranch commented in opposition to registration requirements for authorized pits other than reserve pits, produced water recycling pits, and makeup water pits, stating that neither the industry nor the Commission are equipped to handle the volume of paperwork the registration requirements will create. CrownQuest stated that registration should only be required for pits that are not located on a site with an existing Commission permit or other registration. Momentum Operating asked that pits with less than 80 barrels in total volume be exempt from registration. CrownQuest stated that the Commission should provide more information to operators so they can determine the shallowest expected water and include it on the registration. CrownQuest also expressed general opposition to new requirements for authorized pits, stating that the Commission already has most of the information, that new requirements are too costly and burdensome, and that the Commission has no reasonable basis for imposing the new regulations.

The Commission disagrees. The Commission finds that the pit location and other information required in the registration is necessary to ensure proper regulation of pits that are not required to obtain a permit. Further, it is an operator's responsibility to ensure its facilities do not cause pollution, so the operator should have sufficient knowledge about the groundwater resources in its areas of operations to provide that information on the registration. Generally, the Commission disagrees with CrownQuest that the new regulations are unreasonable or overly burdensome.

Similar to CrownQuest, TIPRO stated that workover and plugging type pits should be excluded from the registration requirement because registering these pits is too big of a burden. There are thousands of these used each year and they are small volume and short term.

The Commission declines to exempt workover and plugging type pits from the registration requirement. It is precisely because there are so many of these pits that the Commission finds they must be registered. When oil field fluids and wastes are placed in an earthen pit the Commission has an interest in knowing that the activity occurred as there is a potential for the pollution of surface or subsurface water.

Regarding the requirement to include in the registration the expected depth to groundwater from the bottom of the pit (proposed in §4.113(e)(4)(D)), EPEC Energy requested clarification regarding how operators should determine depth to groundwater.

The Commission expects an operator to know the occurrence of groundwater at an operational area, and expects an operator will take actions necessary to determine whether groundwater occurs within 50 feet of the bottom of a proposed pit (as required by §4.114 for certain pits). This may require a subsurface investigation, or it may be sufficient to do a records review from the Texas Water Development Board (TWDB) or other source. The TWDB has a website for the groundwater well data viewer and water well drilling reports that can be interpreted to provide groundwater depth. For example, by entering the pit's longitude and latitude, the water data viewer will show the location and water wells in the area. The user may access water well drilling reports for the located wells that will show the depths of the groundwater well screen intervals. By knowing the surface elevation of the pit site at issue, then subtracting the pit depth, an operator can determine the expected depth to the groundwater horizon from the bottom of the pit. For purposes of the liner requirements in §4.114, this method will also enable the operator to determine if the pit bottom is within 50 feet from the groundwater horizon.

The Alliance and Pantera Energy requested the Commission create a registration process that will not create an administrative burden. For example, the Commission could include pit registration requirements on the drilling permit application to consolidate filing requirements where possible.

The Commission intends registration to require minimal effort and be accomplished through a simple online system. The Commission notes that the only registration component subject to Commission staff approval is the financial security requirement for Schedule B pits. The drilling permits system would not meet the Commission's needs because not all authorized pits are associated with a drilling permit.

Diamondback and TXOGA requested clarification regarding how registration and reclassification should be accomplished for pits associated with multiple wells/pads. Commission Shift asked the Commission to clarify whether redesignation of a pit will require re-registration. Commission Shift also requested that the Commission make the registration system publicly available and suggested several additional pieces of data that the Commission should collect via registrations.

The Commission notes that registration details will be addressed prior to the effective date of the rules, which will be July 1, 2025. The Commission intends that operators will be able to accomplish redesignation and other registration updates through the registration system. Other details of the system's capabilities are still under consideration and development.

Several comments were submitted regarding the categorization of reserve pits and mud circulation pits, asking that the Commission require liners and clearer construction standards for these pits. The commenters include Milestone Environmental Services, Gabriel Rio, NESCO, and 400 individuals. Milestone noted that reserve pit failures are the cause of many contamination issues. Similarly, Recover USA commented that operators using drilling fluid which contains at least 1% volume hydrocarbons (oil-based drilling fluid) or chlorides of at least 3000 ppm (brine or salt water drilling fluid) should not be able to utilize a pit unless the pit is built to the same standards as required for Schedule B pits. One individual requested that liners be required for all pits regardless of the pit's distance to the water source.

Several industry associations and operators also commented regarding the list of pits included in §4.113 as Schedule A authorized pits. First, Diamondback, Fasken Oil and Ranch, PBPA, TIPRO, and TXOGA asked that the Commission enable operators to use reserve pits for completion operations. They suggested the Commission change closure requirements to facilitate this practice so that the 30-day dewater and 120-day backfill requirements under §4.114(3)(A)(iii) do not kick in.

The Commission declines to adopt changes to §4.113 or §4.114 based on these comments. The operators is expected to maintain proper pit registration and close the pit with applicable requirements.

Second, the industry associations and operators commented requesting a new suggested pit type- the makeup water pit. The comment relates to the Commission's proposed definition of "fresh makeup water pit" and the associated requirements for fresh makeup water pits in §4.114. The Alliance, Deep Blue, Diamondback, Pantera Energy, PBPA, PPROA, TIP, TIPRO, and TXOGA noted that industry is working to reduce its fresh water use by sourcing water from brackish or saline aquifers. However, the proposed definition and regulation of fresh makeup water pit would discourage the use of alternative water sources. These and other industry commenters suggested that the term "fresh makeup water pit" be replaced with "makeup water pit" and that makeup water pits be subject to the same requirements as mud circulation and reserve pits (e.g., liner requirements if groundwater is present within 50 feet of the bottom of the pit).

As noted above in the comments relating to the definition of "fresh makeup water pit," the Commission agrees to include the new pit type. The Commission adopts Subchapter A with changes to remove the definition of "fresh makeup water pit," add a new definition of "makeup water pit," and replace "fresh makeup water pit" with "makeup water pit" throughout the rules.

Due to the addition of this new pit type and the definition of "makeup water pit" which is defined as "a pit used in conjunction with a drilling rig, completion operations, or a workover for storage of water used to make up drilling fluid or completion fluid" the Commission adopts §4.114 with additional changes to simplify liner and closure requirements for these pits and other Schedule A authorized pits. Revised §4.114(2) retains the requirement that all Schedule A pits be designed, constructed, and maintained to prevent any migration of materials from the pit into adjacent subsurface soils, groundwater, or surface water at any time during the life of the pit. Section 4.114(2)(B) is adopted with changes to specify that any pit that contains fluid with more than 3,000 mg/liter of total dissolved solids (TDS), or any authorized pit located in areas where groundwater is present within 50 feet of the bottom of the pit, shall be lined. The liner requirements proposed in §4.114(2)(B)(i) and (ii) are adopted without changes. "Makeup water pit" is also added to §4.114(3) alongside reserve pits and mud circulation pits so that the closure requirements for reserve pits and mud circulation pits also apply to makeup water pits.

The change requiring liners for any authorized pit (1) containing fluid with more than 3,000 mg/liter of TDS; or (2) located in an area where groundwater is present within 50 feet of the bottom of the pit also attempts to address commenters' concerns that the Commission's regulations governing authorized pits will not prevent pollution. Under the requirements of Rule 8, most authorized pits were not required to be lined, and the proposed rules did not significantly improve the technical requirements of most authorized pits. There were many comments from individuals and organizations on this issue. In addition, there were other comments from some in industry that the proposed requirements for authorized pits were too stringent. The industry comments related to makeup water pits (discussed above) identified the need for water resource pits for brackish water, not just for fresh water. In the adopted rules, the Commission attempts to strike a balance between these interests. All Schedule A authorized pits, which include all authorized pits except for produced water recycling pits, are required to be lined if the pit contains fluid with a concentration of 3,000 mg/l total dissolved solids (TDS) or greater, or if the pit is located in an area where groundwater is present within 50 feet of the bottom of the pit. The Commission chose the 3,000 mg/l threshold because it is the value the Commission uses to identify the base of usable quality water (BUQW). Operators bear the responsibility to not pollute, and if a freshwater resource exists and may be harmed by a pit containing fluid with a lower TDS quality, the operator is required to protect the freshwater resource. Operators have the flexibility to use liners made of natural or synthetic impermeable materials as governed by §4.114(2)(B)(i) and (ii). The Commission determines the requirements to line authorized pits in these situations are adequately protective while also providing some degree of flexibility to oil and gas operators.

Stasney Well Service and Momentum Operating requested the Commission add another pit type in §4.114. They suggested plugging pits be included as Schedule A authorized pits.

The Commission declines to make this change. The definition of "completion/workover pit" (a Schedule A pit) already indicates the pit can be used in plugging. Completion/workover pit is defined as "A pit used for storage or disposal of spent completion fluids and solids, workover fluids and solids, and drilling fluids and solids, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed, worked over, *or plugged*."

Regarding construction standards for authorized pits in §4.114, the Texas Farm Bureau suggested the Commission add requirements for (1) measuring and submitting to the Commission the distance to groundwater; (2) submitting compaction tests to the Commission to determine whether earthen liners can be used; and (3) conducting a more stringent review to liner compliance when a pit overlies a karst formation. Commission Shift requested that the Commission (1) require a minimum of 20 feet between the pit bottom and subsurface water and (2) require groundwater monitoring when subsurface water exists within 100 feet.

The Commission disagrees that this level of design and review is required for Schedule A authorized pits, which are lower volume and operate for a reduced amount of time.

The Texas Farm Bureau and the Texas Bankers Association commented that setbacks should be applied to Schedule A pits.

The Commission declines to impose setback requirements for Schedule A pits. These pits are utilized for drilling and production operations, and common law principles and private contractual agreements establish standards for surface use associated with a mineral lease.

Section 4.114(3) contains the closure requirements for Schedule A authorized pits. The Texas Farm Bureau opposes the provision that allows a pit to remain open for up to one year after cessation of drilling operations. The Bureau suggested the pits be closed as soon as possible but no later than 120 days, similar to Schedule B pits.

The Commission disagrees. The closure time frames are based on the relative risk posed by each type of authorized pit.

CrownQuest stated that there is little difference between a completion pit and a drilling pit. Completion pits should have the same time frame for closure as drilling pits.

The Commission disagrees. First, "drilling pits" are not a specified type of Schedule A authorized pit. Instead, §4.114 addresses reserve pits and mud circulation pits. Closure times for these pits are based on the chloride concentration of the fluids stored in the pit. Higher chlorides concentration requires a faster closure response.

EPEC Energy requested clarification regarding the application of the term dewater to the closure requirements in §4.114 based on the definition of dewater in §4.110. EPEC questioned whether reserve pit waste must meet the EPA paint filter test prior to closure.

The Commission notes that it adopts the definition of dewater with changes to state that dewater means "to remove free liquids from a media such that the remaining material passes a Paint Filter Liquids Test (EPA Method 9095B, as described in 'Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods,' EPA Publication Number SW-846)."

EPEC also requested clarification regarding whether an operator is required to maintain liner integrity during closure and whether breaching the sidewall of a pit during closure for any reason, or using trenching to aid in the rapid disposal of fluids is considered a violation.

The Commission confirms that trenching is not considered a violation. However, closure activities shall not increase the potential for pollution. The Commission adopts changes in §4.114(3) to clarify this requirement.

Stasney Well Service and Momentum Operating commented regarding consistency between proposed §4.114 and §4.111. They stated the Commission should make the two rules the same where possible, especially with regard to defining what is authorized content. Similarly, CrownQuest stated that §4.114 (3)(D), which requires disposal of all wastes in a pit prior to backfilling, conflicts with §4.111 because it seems to require additional requirements than §4.111 and §4.111 is sufficient.

The Commission disagrees with these commenters that §4.111 and §4.114 should be consistent with regard to authorized contents and closure. Section 4.111 addresses specific materials that can be disposed of by burial in certain pits, and those materials are required to be dewatered to remove free liquids. Materials placed in a pit during operational activities are not limited in the same way or for the same purpose.

Section 4.115 of Division 3 contains requirements for Schedule B authorized pits, which are produced water recycling pits. Several commenters requested changes to the financial security requirements for Schedule B pits proposed in §4.115(b), adopted in §4.115(c). The Alliance, CrownQuest, Diamondback, Fasken Oil and Ranch, Pantera Energy, PBPA, TIP, TIPRO, and TXOGA requested that produced water recycling pits located on an existing Commission lease be exempt from the financial security requirements because existing financial assurance associated with an operator's P-5 permit should be considered in those circumstances. PBPA, Diamondback, the Alliance, Pantera Energy, Deep Blue, and TIPRO also requested the Commission incorporate other commonly used financial assurance mechanisms such as self-insurance and parental bonds.

The Commission declines to make any changes to the proposed financial security requirements. The Commission has revised its regulation of non-commercial fluid recycling pits into the Schedule B authorized pit category of produced water recycling pits. Produced water recycling pits are non-commercial; however, because these pits may be very large (1-million-barrel capacity or more), the Commission has determined that a financial security scheme in addition to the operator's normal well-based bonding is appropriate and necessary. The Commission has determined that an operator's well-based blanket bond for lease operations is grossly insufficient to cover the closure costs of produced water recycling pits as the closure requirements are described in §4.115. Some operators have dozens of these pits, and the pit capacities can be larger than 1 million barrels. The Commission estimates that based on closure cost estimates of similar pits that are permitted under Subchapter B, Division 6, closure of a produced water recycling pit may cost from $2 to $3 per barrel of capacity. In addition, the most recently constructed non-commercial fluid recycling pits have registered an average capacity of more than 350,000 barrels. A large operator's bond for well and lease operations is capped at $250,000 for statewide operations. Though the Commission does not alter the financial security requirements based on the comments, the Commission adopts §4.115(b) with changes to clarify that a produced water recycling pit may be located on a tract of land that is not on an oil and gas lease operated by the operator of the produced water recycling pit.

Regarding the suggestion related to parental bonds, the Commission's general regulatory scheme is oriented around an individual operator's Form P-5 organization report and the financial security for the activities undertaken by the operator. The Commission does not have the statutory authority to call in the bond of a parent company. Further, the Commission recognizes that corporate parent-child relationships can be complicated and can change, and the Commission is not in the position to monitor or keep track of those relationships or changes. The financial security system authorized by the Texas Natural Resources Code and incorporated into Commission rules ensures that the Commission can receive the security funding when necessary to step in and close operations at a bonded facility. A bond rating for a corporate entity does not provide that liquidity to the Commission.

PBPA, Diamondback, the Alliance, Pantera Energy, Deep Blue, and TIPRO requested clarification that only one blanket bond is required based on the cumulative number of produced water recycling pits for corporations with multiple subsidiaries.

The Commission will require one bond or blanket bond in the appropriate amount for each P-5 entity who operates one or more produced water recycling pit.

Deep Blue, Diamondback, PBPA, TIPRO, and TXOGA also commented regarding requirements for transfer of a Schedule B pit and recommended language to clarify how transfers must occur.

The Commission agrees that §4.115 should include language to specify how to transfer Schedule B pits and adopts §4.115 with changes to incorporate the requested language in new subsection (m).

CrownQuest commented requesting the Commission remove several provisions of §4.115 because they are overly prescriptive, unduly burdensome, and add no value.

The Commission disagrees. The detailed requirements added in §4.115 are necessary for produced water recycling pits which are large and intend to be operated for many years.

Regarding the proposed siting and setback requirements proposed in §4.115(e), Diamondback, Deep Blue, and TXOGA suggested that language be added in proposed subsection (e)(4) to address water supply wells that may supply water for other purposes besides drilling or workover operations.

The Commission agrees. The Commission notes that due to changes adopted in §4.115, proposed subsection (e)(4) will be adopted as subsection (f)(4) with the requested change.

CrownQuest suggested the words "or intake" be removed from the provision prohibiting produced water recycling pits within 500 feet of any public water system well or intake. CrownQuest noted this term could easily be interpreted as any aquifer used to provide water to a public water system. If the Commission's intent was to limit the distance around a channel type, the Commission already limits these pits to be within 300 feet of surface water, and that should suffice.

The Commission disagrees. The word "intake" allows a 500-foot buffer distance from a public water system that draws from a well (i.e., groundwater) or an intake (i.e., from a surface water feature).

Commission Shift expressed support for the setback from a public area.

The Commission appreciates Commission Shift's support.

Regarding the liner requirements in proposed §4.115(f), adopted in §4.114(g), Commission Shift recommends that when natural liners are allowed, each lift should be required to be properly seated to avoid failure routes. Commission Shift recommended the rules set a minimum thickness of authorized pit liners and require use of ASTM D638 for thicker liners. Also, proposed subsection (f) should require QA/QC documentation to be retained by the liner installer for three years after the pit is closed. As part of the leak detection system, Commission Shift recommends requiring operators to meter the incoming flow rate and use it as a mass-balance check that no leaks have been missed (compare incoming volumes against any volumes leaving the pit, accounting for precipitation and evaporation). These calculations should be reported to the Commission.

The Commission disagrees because it finds the proposed rules sufficiently capture appropriate design, construction, quality control, and records retention requirements. Also, the Commission disagrees that mass balance accounting will add value to the regulation of produced water recycling pits.

Regarding the leak detection requirements proposed in §4.115, Deep Blue, Diamondback, and TXOGA requested the leak detection monitoring frequency be revised to monthly rather than daily.

The Commission agrees and adopts §4.115(h)(4) with the requested change.

Deep Blue, Diamondback, and TXOGA also commented regarding the operating requirements proposed in §4.115(g). They stated that recycling pits generally include some form of treatment which may include separation of waste that can yield small quantities of skim oil, which is frequently removed. The commenters asked whether this activity is prohibited under subsection (g)(6).

The Commission notes that free oil shall not be allowed to accumulate in produced water recycling pits. The Commission understands that some skim oil will be recovered during operations. Recovery of skim oil is not prohibited under proposed subsection (g)(6), which is adopted as subsection (h)(6).

Section 4.115 contains closure requirements for Schedule B authorized pits in subsections (i), (j) and (k). Commission Shift requested that operators be prohibited from using soils or other materials to lower the concentration of pit contents. Commission Shift also noted that background concentrations should not be permissible as the clean-up standard when the background concentrations indicate existing contamination. If background concentrations are allowed, then a certified professional should be required to calculate background to ensure the levels are representative of native background and not previously contaminated soil.

The Commission agrees. Generally, background analysis should be conducted before industrial operations begin at a particular site, and the rules require this consideration (see, for example, §4.115(j)(3)(B), §4.115(k)(2)(C), §4.263(c), and §4.279(c)). If background has not been determined before activities commence, then an operator will be responsible for impacts to the land and surface or subsurface water.

TIPRO and Deep Blue also commented regarding use of background concentrations. They stated that operators should be allowed to follow a similar soil sampling protocol to determine background concentrations to close existing pits because there will be produced water recycling pits in operation when the rule goes into effect. Soil conditions near the pits should suffice for determining background concentrations at closure.

The Commission disagrees. Collecting baseline soil samples post-waste storage and/or disposal activities do not ensure adequate demonstration that waste has been properly managed.

Groundwater monitoring requirements for Schedule B authorized pits were proposed in §4.115(k) and are adopted in §4.115(l). Commission Shift commented that static water level should be measured during every sampling event and a potentiometric surface map created for every event. These measurements and maps should be retained and made public along with all the information required in 4.115(l)(5)(J). Commission Shift also requested the Commission modify proposed subsection (k), adopted as subsection (l), to require sampling of any additional parameter the director directs and to require a more frequent sampling schedule.

The Commission notes that static water levels are required for each sampling event, and operators are required to retain this information. However, the Commission will not require that this information be routinely provided to the Commission; thus, it will generally not be publicly available. The Commission declines to modify the sampling and observation requirements because the Commission believes they are sufficient as written. The Commission also finds that the rules in Division 3 provide sufficient authority for the Director to request additional information if needed.

TXOGA and Diamondback commented regarding proposed §4.115(k)(8), which is adopted as §4.115(l)(8), and the requirement for the operator to notify the Commission when the groundwater monitoring indicates *potential* pollution. They asked the Commission to define what constitutes "potential pollution," how background concentrations of groundwater constituents must be established, and how the source of the pollution must be established so the operator knows what corrective action is required. In the alternative, they suggest the Commission require installation of a downgradient monitoring well before the pit is constructed to determine a baseline and then monitoring of same well after the pit is constructed.

The Commission understands the concern with the term "potential" and adopts §4.115(l)(8) with changes to remove that term.

The Commission appreciates the input from commenters on the rules in Division 3.

Subchapter A, Division 4- All Permitted Waste Management Operations

Division 4 of Subchapter A contains the general requirements for all other waste management activities that are not authorized under Division 3. These waste management activities require a permit before the operator may conduct the activity.

The Commission received several comments related to independent certified lab analysis and lab analysis generally. Diamondback and TXOGA asked the Commission to remove the requirement for independent lab analysis and professional engineer certification of a lab report. They stated that some Commission-regulated facilities have onsite NELAP certified labs. Using an independent NELAP certified lab provides no additional benefit and causes unnecessary delays. Similarly, there is no value in having an engineer who does not perform the sampling or conduct the analysis certify the report.

The Commission declines to remove requirements for independent certified lab analysis and professional engineer certification. For permitted operations, the Commission has long required laboratory analytical results submitted to the agency to be collected by an independent certified laboratory. Similarly, geotechnical laboratory analysis should be overseen and certified by a licensed professional engineer.

NESCO and Commission Shift stated that an independent professional consultant should perform all environmental monitoring and an independent laboratory should perform all analytical testing.

The Commission agrees with NESCO and Commission Shift that in most cases this is true. The Commission recognizes field analysis performed by calibrated equipment can be sufficient.

Commission Shift also suggested that full lab reports and chains of custody be submitted to the Commission and made publicly available.

The Commission notes that when its rules require operators to submit laboratory analytical data, the Commission expects the data to be submitted as a complete package (with quality control data, chains of custody, etc.). The Commission collects chains of custody as part of quarterly reports. All filings made to the Commission are publicly available via the Texas Public Information Act.

NESCO requested Division 4 be revised to require operators of commercial facilities to report any noncompliance within 24 hours and then provide written notification of noncompliance within five calendar days.

The Commission notes the rules contain several provisions requiring operators to report issues such as leaks, spills, and contamination either immediately or within specified time frames. The Commission declines to incorporate additional language based on this comment.

Section 4.120 contains the general requirements for all permitted operations. CrownQuest asked for revisions to §4.120 to specify that Division 4 "does not apply to waste associated with drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, or natural gas per 40 CFR 261.4 (b)(5)."

The Commission disagrees. Division 4 expressly applies to these wastes. Oil and gas waste is exempt from RCRA hazardous waste rules but is not exempt from the Commission's rules that prohibit pollution and require waste management.

CrownQuest also commented regarding §4.121(a), which provides that a permit issued pursuant to Divisions 4 through 9 is valid for not more than five years. CrownQuest stated that adding a permit term creates uncertainty and burdens operators. Many of the applications costs hundreds of thousands of dollars. CrownQuest asked for the Commission to explain why a permit term matters.

The Commission makes no changes in response to this comment. Waste facilities that serve the oil and gas industry have a finite lifespan with finite capacities for waste treatment, storage, and disposal. It is appropriate then, that the authorization for the facility's activities also be limited in time, which provides an opportunity for the Commission, the facility, the public, and the industry to assess the efficacy of the specific facility and the waste management methods employed. A five-year term has been traditionally adopted in practice by the Commission, and the Commission intends to continue that practice. Further, a perpetual permit for an activity or facility is not appropriate in a regulated industry with multiple classes of stakeholders.

Commission Shift requested clarification regarding whether permits issued under Rule 8 will be updated with the permit conditions required by new Division 4, as applicable, when the permits are required to be renewed or modified. Commission Shift asked whether the public will have an opportunity to participate in the renewal or modification process. Commission Shift also noted that all renewals, transfers, and amendments should comply with the rules in effect at the time a request is received by the Commission, and that notice should be required for all renewals, transfers, and amendments.

The Commission notes that pits permitted under §3.8 and operating at the time of the effective date of these rules (July 1, 2025) may continue to operate pursuant to their existing permits. When those permits expire, new permits will be issued pursuant to the new rules. Section 4.122(a) describes the considerations for transitioning permits from regulation under §3.8 to regulation under Subchapter A of Chapter 4. The Commission agrees that renewals, transfers, and amendments must comply with the rules in effect at the time. Section 4.122(a) describes how the Commission intends to ensure compliance when transitioning permits. However, some deviation will be necessary, as explained by §4.122(a)(1)-(4). Requiring facilities to meet the new rules is not always practical or possible. The Commission will amend permits when necessary to prevent pollution of surface or subsurface water or to prevent other risks to human health and safety. The new rules require notice upon renewal or amendment of a permit. So, notice will occur at least every five years alongside permit renewal. The Commission may require notice of a transfer if there is good cause.

Commission Shift also commented regarding §4.122(b), which requires the permittee to file an application for renewal at least 60 days before the permit expiration date. Commission Shift stated that 60 days is not enough to ensure renewal applications are filed and reviewed prior to the time the original permit expires. If an original permit is allowed to remain pending during review of the renewal, the operator can prolong the process by asking for repeat amendments and continuing to operate under the old permit.

The Commission agrees that 60 days may not be sufficient for processing a complex renewal. However, the Commission has increased staff and is committed to more efficient processing of permits and renewals, as well as improved compliance. The Commission is better equipped to manage permits and renewals and prevent operators from taking advantage of processing delays.

For good cause, §4.123 allows the Commission to modify, suspend, or terminate a permit issued pursuant to §3.8 prior to the effective date of new Subchapter A. The Commission received two comments on good cause. CrownQuest asked that the factors proposed in subsection (b)(4)-(8) be removed, stating that the factors in subsection (b)(1)-(3) are the factors that matter.

The Commission declines to delete subsection (b)(4)-(8) because the Commission will consider those factors when determining good cause. Thus, the rule should provide certainty to operators regarding what will be considered.

Commission Shift asked whether evidence collected by the public and provided to the Commission can support a finding of good cause. The Commission acknowledges that information provided by the public may prompt the Commission to propose modification, suspension, or termination of a permit. The Commission notes that the modification, suspension, or termination is not effective until notice is provided and a hearing conducted. Whether the evidence provided by the public "supports a finding of good cause" is a legal question to be determined in the hearing.

NESCO and Commission Shift commented that the phrase "relevant calibration records" in §4.124 is too vague. They suggest that calibration be required before first use and then at least every 6 months in addition to after any repair.

The Commission disagrees. Section 4.124 states that all NORM instruments shall be "properly calibrated." Demonstration of "proper calibration" will be the burden of the operator/tester and includes compliance with the instrument manufacturer's recommendations. The requirement to submit information showing the last calibration date and the requirement to submit the manufacturer's specifications will allow the Commission to determine whether calibration frequency aligns with the manufacturer's specifications.

NESCO and Commission Shift also requested that the Commission require additional components to be included in permit applications submitted under Division 4. The additional components include: a community relations plan, a proposed inspection checklist, information on other permits within a 30-mile radius filed within the last ten years, the location of all public water supply wells and private water wells within a one-mile radius of the facility boundary, and the location of all residential, commercial, or public buildings and hospitals within one-half mile of the facility boundary.

The Commission declines to revise the application requirements in response to these comments. The Commission notes that Division 4 includes several provisions that provide the Director with authority to request additional information. The Commission also notes that it reviews permit applications and checks for water wells and sensitive features such as residential, commercial, or public buildings, and churches, schools, and hospitals located within a one-mile radius.

The Commission received several comments on §4.125, which contains the notice requirements for operations permitted under Subchapter A. The TSCRA commented that notice should be provided well in advance of any action and should contain sufficient details about the activities and materials at issue.

The Commission understands these concerns. Section 4.125 provides 30 days from the date of notice for an affected person to file a protest. In addition, Section 4.125 requires the operator to provide a complete copy of its application as well as a letter providing more straightforward information about the proposed facility and the types of fluid or waste to be managed. The Commission finds that the notice period and contents proposed in §4.125 address the concerns expressed by TSCRA.

CrownQuest asked the Commission to remove the requirement to send a complete copy of the application with the notice because the applications are too large and will cause confusion for recipients.

The Commission disagrees. The Commission finds the public should be able to review the complete application. The Commission notes that a notice letter is also required to be sent with the application, and the straightforward information in the letter will assist recipients in understanding the permit application.

Regarding the 30-day protest period referenced in proposed §4.125(b), (d)(3)(F), (f), and (f)(1), TIP commented requesting the Commission clarify the date the protest period begins. Some references state, "the date notice is provided" while others state "the date of notice." TIP stated it believes the intent is to use the date indicated on the notice itself.

The Commission agrees that the start date for the 30-day protest period should be clarified. The Commission adopts §4.125 and other notice provisions with changes to clarify that the 30-day period begins when notice is completed, which occurs upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

Sierra Club and 57 individuals requested that the Commission require two notices be sent to affected parties- one notice prior to filing the application and a second notice once the application is determined complete by the Commission.

The Commission disagrees. Section 4.125 ensures notice is not provided until the Commission determines the application is complete. This approach prevents protests to a permit based on contents that are no longer accurate.

CrownQuest asked the Commission to remove the requirement to notify adjacent surface owners, the district office, and any other people the Director determines should receive notice. CrownQuest believes that if the Commission wants certain persons to be notified then the Commission should notify those persons.

The Commission disagrees that it should be responsible for notifying certain persons of permit applications. The operator applying for a permit has responsibility and is in the best position to represent the operator's proposal to persons required to be notified.

Sierra Club, Commission Shift, and 57 individuals asked that §4.125 be revised to require notice to all residents, landowners, and groundwater conservation districts within one mile of the proposed property. Commission Shift and the 57 individuals also commented that notice should not be limited to cities but should also be provided to towns and villages when proposed facilities are located within the jurisdiction of the town or village.

The Commission declines to expand §4.125 to require notice be provided to these persons.

NESCO commented that affected party status should be determined by distance rather than contiguity. The migration of pollutants does not stop at arbitrary boundaries like a highway. Commission Shift and 57 individuals asked that distance measured for notice purposes begin at the facility's boundary.

The Commission notes that §4.125(c) includes a notice provision based on distance in addition to a notice provision based on contiguity: subsection(c)(3) requires notice be provided to surface owners of tracts located within 500 feet of the facility's fence line or boundary, even if the tract is not adjacent to the tract on which the facility is located. The same provision specifies that the distance is measured from the facility boundary, in accordance with what Commission Shift and the individuals requested.

Regarding the method of notice, Commission Shift commented that published notice should be required for all facilities, not just commercial facilities permitted under Division 5. Commission Shift also requested that the Commission create a public notice website, so notice materials could be posted by applicants and viewed by the public online.

The Commission's online application LoneSTAR allows for the online filing and tracking of regulatory Oil and Gas Division functions. Technical Permitting functions, including permitting under new Subchapter A, are in development to be added to LoneSTAR. Though the application's functions have not yet been fully scoped, the system will provide the public better access to application materials and other filings. As development progresses, the Commission will consider whether an online notice component can be incorporated.

Regarding location and real property information required to be included in an application under §4.126, CrownQuest suggested the Commission remove the requirements proposed in subsection (a)(2)(A) and (a)(2)(B) relating to surface owners and the property's legal description. CrownQuest believes there is no value to this information for the Commission and it is not something the Commission should regulate. CrownQuest also requested the Commission refrain from specifying the required map size and scale and instead require the map be discernable.

The Commission declines to make changes in response to these comments. Information related to surface ownership is important so the Commission can confirm compliance with notice requirements. Map specifications are intended to ensure operators know what the Commission needs in advance to aid in quicker permit processing times.

Regarding §4.127, Commission Shift commented that site investigations should be required for all permitted operations. Thus, Commission Shift suggested revising language in subsection (b) that only requires a site investigation if engineering and geologic information is not available.

The Commission declines to make changes in response to this comment. The Commission notes that flexibility is required to address situations where a site investigation is not necessary.

Regarding §4.128, relating to Design and Construction, Waste Management requested that the Commission revise the requirement that letters and numerals on signage be at least six inches in height. Waste Management noted the change will require new signs, sign holders, and posts at all applicable facilities.

The Commission agrees and adopts §4.128(b)(1) to revise the requirement to three inches rather than six.

Waste Management also requested that the Commission allow double wall, above-ground fuel tanks that are inspected monthly for secondary containment rather than the requirements proposed in §4.128(b). Commission Shift asked that secondary containment be required to contain the maximum capacity of all tanks supported by the secondary containment, not just the capacity of the largest tank. In addition, the secondary containment should have freeboard to contain precipitation from a 25-year, 24-hour rainfall event.

The Commission declines to make changes in response to these comments. The Commission declines to allow double wall, above-ground fuel tanks because the secondary containment requirements in the proposed rule are consistent with permit conditions in current permits. The Commission disagrees with Commission Shift that §4.128 should be revised to specify secondary containment requirements when multiple tanks are at issue.

Regarding compaction requirements proposed in §4.128(b)(2), Waste Management commented that the requirements are excessive and asked for clarification regarding the Commission's purpose for proposing them.

The Commission disagrees the requirements are excessive and notes the proposed compaction requirements are consistent with current permit conditions.

Waste Management recommended the Commission revise the requirements related to security to prevent confusion.

The Commission agrees the language could benefit from revisions but declines to adopt Waste Management's proposed language, which the Commission believes does not communicate the intent of the provision. The Commission adopts §4.128 with changes to clarify that a facility is required to maintain security to prevent unauthorized access. Security requirements are met by (1) a 24-hour attendant; or (2) if not attended, a six-foot-high security fence and locked gate to prevent livestock or vehicle access.

Section 4.129 addresses requirements for operation of permitted facilities in Division 4. TXOGA and Diamondback commented on proposed §4.129(b)(1), which states a permittee may only accept waste transported and delivered by a permitted waste hauler. The commenters note that a permitted waste hauler should not be required if the waste at issue is inert waste and requested a change to make that clear.

The Commission agrees that hauling of inert waste is excluded in §4.193, which is part of Division 10. Section 4.129(b)(1) already references Division 10. Thus, the exclusion under §4.193 is incorporated into subsection (b)(1) and the Commission does not agree that additional changes to subsection (b)(1) are necessary.

NESCO asked the Commission to ensure that wood chips are not allowed to be added to waste to make waste pass the paint filter test. Wood chips are only a bulking agent- they do not create any chemical change in the waste.

The Commission finds that wood chips are sometimes appropriate as a waste additive. Wood chips have unprocessed cellulose, hemi-cellulose, and lignin that may lower the pH of liquids and absorb liquids. The Commission will evaluate acceptable use of wood chips as a waste additive during the permitting process pursuant to §4.120, which states that a permit may be issued only if the Commission determines that the activity will not result in the endangerment of human health or the environment, the waste of oil, gas, or geothermal resources, or pollution of surface or subsurface water. If an applicant demonstrates that a waste additive furthers these objectives the Commission may approve its use.

TXOGA and Diamondback commented that the spill reporting requirements proposed in §4.129 appear to conflict with existing requirements in §3.91.

The Commission disagrees. Section 3.91 governs crude oil spills whereas §4.129 governs all oil and gas waste spills.

NESCO and Commission Shift stated that §4.129(b)(4)'s requirement that any spill of waste, chemical, or any other material be collected and containerized within 24 hours is too long. They recommend the permittee be required to "promptly containerize" waste or take immediate corrective action.

The Commission disagrees because it is not always feasible for an operator to reach the location of a spill within 24 hours.

Waste Management commented regarding §4.130, relating to Reporting. Waste Management noted that certification cannot be made electronically and suggested the term "application" in proposed §4.130(c) be changed to "report."

The Commission agrees and adopts §4.130(c) with the suggested change.

Commission Shift requested clarification regarding §4.130 and when permittees are required to submit reports. Commission Shift recommended the Commission state clearly if all reports are required to be filed electronically.

The Commission agrees that its intent is to require all reports to be filed electronically once an electronic system is established. All report requirements apply regardless of whether an electronic filing system exists. However, once an electronic filing system is established, operators are encouraged to use that system. One year after the electronic filing system is established, use of the electronic system will be mandatory - the Commission will no longer accept paper filings at that time. The Commission adopts §4.130 with changes to clarify this requirement.

The Commission received several comments on the monitoring requirements proposed in §4.131.

Dr. Brownlow and Dr. Rogers stated that distance to groundwater is not the most helpful measurement. The characteristics of the soil underlying the pit should be taken into account. They suggested the Commission require a site analysis to consider the lithology and aquifer characteristics beneath the site to better assess threat of groundwater contamination.

The Commission agrees and notes that Technical Permitting staff evaluate the soil characteristics when reviewing permit applications. The Commission makes no changes in response to this comment.

Commission Shift suggested several changes to §4.131(b) relating to groundwater monitoring. First, Commission Shift requested that language proposed in subsection (b)(2) be relocated to (b)(1) to ensure monitoring wells are required for all facilities. They also suggested deleting language stating that monitoring wells "may be required." Second, Commission Shift asked that BTEX be added to the list of constituents the permittee must sample under subsection (b)(4). Third, Commission Shift stated that monitoring well locations should be established only after the soil boring data has been fully analyzed by a certified professional because this will ensure the site's groundwater gradient is understood.

The Commission makes one change in response to these comments. Section 4.131(b)(4) is adopted with changes to add BTEX to the list of constituents. The Commission disagrees that the language in subsection (b)(2) should be moved to (b)(1). The Commission will not mandate monitoring wells for all sites but will review the need for monitoring wells on a case-by-case basis. Thus, requirements in §4.131(b)(2) are applicable to all required monitoring wells and §4.131(b)(1) describes how Commission staff will evaluate the need for groundwater monitoring wells. Regarding analysis of soil boring data, the Commission expects the operator to determine the groundwater depth and flow direction, and then locate the monitoring wells appropriately to assess conditions upgradient and downgradient from the waste activity. More than three soil borings may be required, and more than three monitoring wells may be required. It is the operator's burden to establish the groundwater conditions and monitor them accordingly.

NESCO also requested several changes to the proposed groundwater monitoring requirements. NESCO recommended that quarterly groundwater monitoring be required for all commercial facilities, that monitoring wells be protected from damage by vehicles and heavy equipment, that monitoring wells be maintained in good working condition with a lockable water tight expansion cap, and that the operator be required to measure groundwater levels monthly for a period of two years to determine seasonal fluctuations in the water table.

The Commission declines to make changes in response to these comments. Section 4.131(b)(2)(E) states that groundwater monitoring wells must be compliant with 16 TAC Part 4, Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers). Current groundwater permit conditions have existing protections for vehicles/heavy equipment and water tight caps. The Commission disagrees that groundwater monitoring should be required for all facilities. Not all facilities are located in an area with geological conditions necessitating mandatory groundwater monitoring. The Commission's staff will evaluate site specific conditions for permits. Regarding reporting related to groundwater levels, Commission permits require monitoring on a quarterly basis to evaluate any trends. The Commission does not agree this data should be collected monthly.

NESCO and Commission Shift requested clarification regarding requirements for upgradient groundwater monitoring wells.

The Commission notes upgradient wells are usually required but the Commission's staff will evaluate proposed monitoring well locations on a case-by-case basis to ensure the site properties are considered. Thus, a requirement for upgradient monitoring wells is not included in §4.131.

Commission Shift and NESCO also commented regarding situations in which an operator should be required to voluntarily cease operations such as when groundwater monitoring wells are not functional or cannot be sampled, if an operator fails to submit required information to the Commission, or when potential pollution or liner failure is detected.

The Commission declines to make changes due to these comments. The Commission has the authority to suspend operations and will consider whether to impose that authority on a case-by-case basis. The Commission agrees that continued operations at a facility are not permissible when the required groundwater monitoring program is not operable. Regarding liner failure, the Commission notes that response actions will be coordinated with the District Director, who has the authority to inspect a possible liner failure.

Section 4.132 contains closure requirements for permitted facilities. TXOGA and Diamondback asked that the Commission allow proposed soil sampling protocol to apply to closure for existing pits. Soil conditions near existing pits should suffice for determining background concentrations at closure.

The Commission disagrees. Collecting baseline soil samples post-waste storage and/or disposal activities does not adequately demonstrate that waste has been properly managed.

Commission Shift and NESCO recommended changes to require closure and post-closure estimates to be prepared by a licensed professional engineer or professional geoscientist and to require estimates to be based on R.S. Means Cost Data.

The Commission notes that closure cost estimates are not required for all permitted facilities, only commercial facilities. Division 5, which contains specific requirements for commercial facilities, states that the closure cost estimate must be prepared or supervised and approved by a licensed professional engineer and the estimate must show all assumptions and calculations used to develop the estimate.

Commission Shift stated that if closure plans are not equally protective of human health and the environment as the plans included in the permit (for which public notice was given) then the Commission should require additional public notice of the revised closure plans.

The Commission agrees that if a closure plan is not consistent with closure activities described in the permit, then a permit amendment would be required.

Commission Shift recommended a change in §4.132(b)(3) so that additional closure operations are required rather than optional when soil samples exceed the authorized limits.

The Commission declines to make the requested change. Commission staff will evaluate non-compliant facilities and determine the appropriate responses on a case-by-case basis.

Section 4.134 specifies that the Technical Permitting Section will review applications in accordance with §1.201, relating to Time Periods for Processing Applications and Issuing Permits Administratively. CrownQuest commented that the rules incorrectly focus on technical compliance with paperwork requirements rather than the substance needed to determine whether to issue a permit. The Director should be given additional discretion not just to require more information (like in §4.135) but to accept less information.

The Commission disagrees. As just described in response to numerous comments requesting that the Commission impose additional permit requirements (both technical and paperwork-related), the Commission declined on the basis of maintaining flexibility to consider the specific facts of the proposed facility. Further, Section 4.109 gives the Director the authority to approve an exception, which could include a request to provide less information, provided the change is equally protective of public health, safety, and the environment as the provision to which the exception is requested.

NESCO and 57 individuals asked the Commission to prohibit additional changes in an application after it has been determined administratively complete. They also request that no changes be permissible once an application is submitted for a hearing.

The Commission disagrees because once a permit application is the subject of a hearing, the hearings procedures govern the permit's outcome.

NESCO and Commission Shift submitted comments related to timelines for issuing proposals for decision after a contested case, and suggested requirements for final orders that are adverse to the proposal for decision.

These suggestions are outside the scope of this rulemaking and are more appropriately addressed under the Commission's practice and procedure rules in Chapter 1.

NESCO asked the Commission to add a requirement that no more than two supplemental filings may be submitted during the permit application process. NESCO and Commission Shift stated that Commission staff should be able to deny an application as technically deficient without allowing the applicant an opportunity for a hearing.

The Commission notes the requirements for permit processing are addressed in §1.201. Commission staff will comply with these requirements. The opportunity for a hearing is standard practice at the Commission. The Commission declines to alter that practice for permits governed under Chapter 4 because it would be inconsistent with other permit processes at the Commission.

Subchapter A, Division 5- Additional Requirements for Commercial Facilities

Divisions 5 through 9 contain requirements for certain waste management activities. Operators of facilities governed by these divisions must comply with the requirements set forth in the division in addition to the requirements set forth in Division 4. Facilities may be governed by more than one division in addition to the general requirements of Division 4. Division 5 contains the additional requirements for commercial facilities.

Generally, NESCO commented that a commercial facility's history of compliance should be considered when a new permit application, renewal, or amendment is filed. Commercial facilities that fail to comply with the rules or permit conditions should not be allowed to continue to operate.

The Commission notes that Texas Natural Resources Code §91.114 governs how the Commission must address new permit applications when the applicant has violated a statute, Commission rule, or an order, license, certification, or permit issued by the Commission that relates to safety or the prevention of pollution. The Commission will continue to adhere to §91.114.

CrownQuest also submitted general comments that the proposed rules for commercial facilities in Division 5 will cause many facilities to shut down to avoid the regulations and will decrease the amount of produced water recycled.

The Commission disagrees. The requirements in Division 5 are designed to incorporate pollution protections that are common permit conditions for commercial facilities.

NESCO commented that Commission inspectors should be able to shut down a commercial disposal facility on the spot for egregious violations or if any monitoring wells are not operational.

The Commission notes that Commission rules such as §4.150(f) require operators to take any measures necessary to stop or control an unauthorized release and report the release to the District Office within 24 hours. Further, Texas Water Code §26.131 provides the Commission authority to shut down activities that are causing harm to surface and subsurface water. The Commission has exercised this authority and will continue to do so when appropriate.

Waste Management and Commission Shift asked for clarification regarding the facilities subject to the requirements in Division 5 and how those facilities differ from the commercial facilities governed under Subchapter B.

The Commission notes that Subchapter B applies to commercial recycling facilities only. The facilities required to comply with Subchapter A, Division 5 are commercial facilities that conduct other waste management activities. In reviewing these comments and the proposed language in §4.140, the Commission noticed one reference to stationary commercial fluid recycling that should not be included in §4.140. The Commission adopts §4.140(h) to remove that reference. The Commission expects this will increase clarity regarding the application of Subchapter A and Subchapter B.

Commission Shift and NESCO commented that post-closure monitoring periods should be greatly increased to a minimum of 10 years.

The Commission disagrees and keeps five years as the minimum. The rules provide the Commission discretion to require a longer time period if needed.

Section 4.141 addresses additional notice requirements for commercial facilities. Commission Shift asked the Commission to expand the notice radius for commercial facilities to require notice for affected persons within one-half mile of the facility boundary. Commission Shift also requested notice be provided electronically similar to the suggestion in its comments on §4.125.

The Commission declines to make changes in response to these comments. As stated in its response regarding §4.125, the Commission will consider whether to incorporate a notice function in the LoneSTAR application while it is in development.

Regarding §4.142's requirement for a stormwater management plan, Waste Management requested "stormwater" be changed to "contact stormwater."

The Commission disagrees. The Commission expects the operator to manage all stormwater on the facility, which includes run-on, segregation of contact stormwater from non-contact stormwater, and run-off or discharge. Stormwater management plans submitted with an application must identify how both contact and non-contact water will be addressed so that Commission staff can ensure non-contact water is appropriately separated from contact stormwater. This oversight includes the ability to require non-contact stormwater authorizations be provided to the Commission when deemed appropriate.

Regarding §4.143, Commission Shift and NESCO recommended as-built drawings be required prior to commencement of operations. Commission Shift recommended that vertical aerial photos be required every two years.

The Commission agrees it should have information regarding the as-built condition of the facility and those requirements were included in proposed §4.143, which states, "Prior to commencement of operations at a commercial facility, the permittee shall provide the Director with drawings documenting the as-built condition of the facility." In addition, Commission inspections evaluate the as-built condition of the facility and whether it complies with the permit. A requirement to submit photos every two years is not necessary because inspections will verify facility conditions in person.

Subchapter A, Division 6- Additional Requirements for Permitted Pits

Regarding Division 6, NESCO commented requesting the Commission add a requirement that any spill of waste, chemical, or any other material, shall be promptly containerized and disposed of in an authorized manner. NESCO also requested additional requirement related to landfills, such as greater setbacks and more provisions related to waste tracking within the facility.

The Commission declines to adopt this specific language but notes that proposed §4.150(f) requires the operator to take any measures necessary to stop or control a release in the event an unauthorized release occurs. The operator must also report the release to the District Office within 24 hours. Regarding NESCO's comments on landfills, the Commission disagrees that additional requirements are needed. Disposal pit permits are integrated into overall facility designs and are regulated accordingly.

Commission Shift commented on the proposed setbacks in §4.150. Commission Shift requested the Commission add setbacks from sensitive residential, commercial and other buildings. This could be accomplished by using "public area" and incorporating a setback from public areas for all permitted facilities.

The Commission agrees and will adopt a setback prohibiting pits within 500 feet of a public area. Section 4.150(g) is adopted with this change.

Commission Shift requested that exceptions for setbacks not be allowed without public input and that setbacks be measured from the facility's property boundary.

The Commission believes the proposed rule ensures exceptions will not occur after notice has already been provided. The proposed rules require that notice be provided after the permit application is determined by Commission staff to be administratively complete. Any exception request would occur prior to that determination. The Commission disagrees that setbacks should be measured from the facility's boundary. The setback distances are measured from the waste management unit, and the Commission finds this is appropriate.

Commission Shift commented regarding §4.150(f), which requires an operator to notify the District Office within 24 hours of an unauthorized release. Commission Shift asked that notice be provided to the public as well.

The Commission declines to make any changes in response to this comment. The Commission notes that any notification submitted to the District Office will be logged into the Commission's Inspection, Compliance, and Enforcement (ICE) system. Once the matter is processed, it is posted in the Commission's Online Inspection Lookup (OIL) system. Both of these systems are public and allow members of the public access to information related to §4.150. In addition, the Commission routinely works with emergency responders and other public officials on response situations that warrant broader and quicker public notification.

Regarding §4.152, Diamondback and TXOGA requested the Commission allow the director's designee to inspect a liner repair so there is not delay while waiting for inspection.

The Commission agrees that the director's designee may inspect the liner but notes that the definition of District Director contemplates authority delegated by the director. Thus, the requested change is not required.

Commission Shift also commented on §4.152, requesting that an operator be required to notify the Commission within 24 hours any time failure of the primary liner is indicated as described in §4.152(b)(1)(A)-(C).

The Commission declines to make the requested change because §4.152(b)(3) already requires the operator to notify the Director and the District Director within 24 hours of discovery of a liner failure. However, due to Waste Management's comments described in the next paragraph, the Commission adopts §4.152 with changes to address required corrective action upon discovery of a liner failure.

Waste Management recommended the Commission allow an alternative process in §4.152(b)(3) in the event the pit is a disposal pit and cannot be emptied.

The Commission agrees and adopts §4.152(b)(3) with changes to address this comment.

Subchapter A, Division 7- Additional Requirements for Landfarming and Landtreating

Regarding Division 8 generally, Commission Shift requested several additions to the rules such as specifying which wastes may be landfarmed, setting size limits on landfarm cells, incorporating components of Commission guidance into the rules, and prohibiting landfarm permits where shallow groundwater is present.

The Commission declines to add these suggested requirements. Technical Permitting reviews each land application, landfarming and landtreating permit application on a case-by-case basis and issues permit provisions based on site-specific recommendations. Permits specify the type of waste that may be landfarmed. The Commission does not deny permit applications when shallow groundwater is present. Instead, the Commission determines whether the specific proposal will prevent pollution.

The shallow geology may provide adequate confinement from downward migration of applied waste materials.

Commission Shift commented that the same setback provisions from Divisions 4-6 should be incorporated into Division 8.

The Commission agrees and adopts §4.161 with the requested change.

Regarding proposed §§4.161 and 4.162, Commission Shift requested the Commission require a topographic map and aerial photos depicting facility and constructed properties to ensure the facility complies with setbacks, more detailed soil sampling and increasing sampling frequency, documentation of amendments and microbes used to treat the soil, and more detailed requirements for berm maintenance.

The Commission declines to add the suggested requirements. The Commission determines that topographic maps and aerial photos are not needed for the shorter-term activities permitted under Subchapter A, several of which have required buffers/setbacks. For longer-term activities, the Commission finds the proposed permit application contents are sufficient. The permit application and review process will provide Commission staff a sufficient basis for evaluating the proposed location of a facility. The proposed sampling and analytical parameters provide the operator and the Commission sufficient information to make informed decisions regarding the operations of the facility and the protection of surface and subsurface water. The proposed rules require amendments and microbes information to be provided in the permit application, and the actual use of treatment amendments is required to be provided in quarterly reports. In addition, permits are written to ensure maintenance of the facility and required structures, such as berms.

Commission Shift commented regarding §4.163(d) and the ban on accepting waste once a parcel exceeds the parameter limitations after six months of sampling. Commission Shift questions the six-month timeframe and recommends the ban go into effect if sampling shows exceedances even one time.

The Commission declines to make the requested change. Exceedances in parameters may be due to a number of environmental factors that could be short-term (e.g., recent rainfall and/or drought) and those exceedances could be mitigated with soil amendments and tillage, which introduces oxygen, of the waste into the soil profile. The Commission aims to implement a holistic perspective that allows the operator to mitigate the exceedance and correct problems through additional operational measures rather than terminating the operation, especially considering the exceedance may not be caused by operations but by environmental factors.

Commission Shift requested clarification regarding closure parameters for landfarms and other specific closure requirements applicable to landfarms.

The Commission notes that closure requirements for all landfarming and landtreating facilities are contained in §4.164. Commission staff evaluates whether additional closure requirements are appropriate on a case-by-case basis and, if so, incorporates the additional requirements into the permit.

Subchapter A, Division 8- Additional Requirements for Reclamation Plants

Division 8 describes the requirements applicable to permitted reclamation plants and is substantively similar to current §3.57 (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials), which is amended concurrently with the new rules in Subchapter A.

United Environmental Services LLC commented opposing the requirement for reclamation plant pit permits to be renewed every five years. United stated, "Requiring permit renewal every five years will not prevent bad operators from bad practices. It will equally burden good and bad operators with administrative requirements, but will not encourage compliance with rules. If instead the point of the new requirement is to get updated information about the facility and surrounding landscape, the Commission can do that through a requirement for the operator to provide updated information. Going through the application process increases costs and creates uncertainty due to contested proceedings."

The Commission disagrees. Incorporating permit expiration dates ensures plant permits contain relevant requirements-requirements that reflect current facility operations and incorporate any regulatory updates.

Commission Shift suggested that reclamation plant permits existing on the date the rules go into effect expire one year after the effective date, rather than five years. Commission Shift also commented opposing the change that allows operators to transfer reclamation pit permits, an option that was not available under the prior rule §3.57.

The Commission disagrees. Because reclamation plant permits do not currently expire, the Commission considers a five-year term to be appropriate. This will provide operators and staff sufficient time to make the adjustment. Current reclamation plants remain subject to Commission permits and inspections. The Commission also disagrees that the ability to transfer a reclamation plant permit should be removed. The Commission proposed two main changes to reclamation plant requirements in Division 8: (1) incorporating a permit term; and (2) allowing permit transfers. The Commission finds these two new requirements create a balance for operators and staff and the Commission declines to make any changes based on the comments.

Hance Scarborough commented regarding the requirement for the waste generator to characterize waste. It noted that current reclamation plant permits require representative samples of waste from commercial oil and gas facilities and reclamation plants to be analyzed for either Total Organic Halides (TOX) or Extractable Organic Halides (EOX) prior to receipt at the permittee's site. If TOX/EOX testing is to be required prior to receipt at a reclamation facility, such testing should be the responsibility of the generator of the waste stream as part of the characterization process, and not the responsibility of reclamation facility permittees.

The Commission agrees. Characterization is the responsibility of the generator when the generator is considering options for the disposition of the waste. When the waste arrives at a reclamation plant, it should already have been characterized. The reclamation plant operator, as a receiver, should only accept waste that has been characterized. No rule changes were made in response to this comment.

Relatedly, Commission Shift requested the rules be revised to require lab analysis for waste being received at reclamation plants.

The Commission disagrees. Process knowledge is sufficient to characterize most oil and gas waste that is subject to the RCRA exemption. In addition, the enhanced waste transportation requirements in Division 10 will help the Commission, generators, transporters, and receivers to ensure the integrity of the waste classification and receipt of transported waste.

Commission Shift commented regarding notice of reclamation plant permits stating that interested parties should be able to participate in the permitting process.

The Commission notes that reclamation plants are subject to the requirements of Divisions 4, 5, and 6 of Subchapter A in addition to the requirements of Division 7. The applicable notice requirements in those divisions, which include notice by publication, will ensure notice is provided and affected persons have an opportunity to protest.

Regarding §4.170(a)(3), Commission Shift requested information regarding how many facilities do not file monthly reports. Commission Shift is referring to the following statement in subsection (a)(3): "The removal of tank bottoms or other oil and gas wastes from any facility *for which monthly reports are not filed with the Commission* shall be authorized in writing . . ."

The Commission notes that it appears there is confusion regarding the meaning of subsection (a)(3). The facilities stated in this portion of subsection (a)(3) are not reclamation plants, they are oil and gas properties/facilities that are not otherwise required to submit monthly reports to the Commission. An example is a disposal well whose tank bottoms are sent to a reclamation plant. The disposal well is not required to file a monthly report. Therefore, the movement of the oil-bearing tank bottoms must be authorized individually by the Commission, and §4.170(a)(3) describes how such an operator would obtain an "Oil Movement Letter" authorizing this action. The Commission adopts no change to §4.170(a)(3).

Commission Shift made two suggestions related to §4.173. First, Commission Shift asked that the Commission establish an electronic filing system for reclamation plant reports within one year of the rules' effective date. Second, Commission Shift asked the Commission to reexamine the language in subsections (c)(1) and (c)(2). It is unclear if the intent is to differentiate based on whether the waste comes from a pipeline facility or from other sources or if it is to differentiate between tank bottoms and "other" waste.

As mentioned in response to other comments, the Commission's updates to the LoneSTAR system will provide more functionality for permitting and reporting. Regarding subsections (c)(1) and (c)(2), the former relates to how crude oil and condensate are reported on Form PR (Monthly Production Report) or Form T-1, (Monthly Transporter Report.). The latter (subsection (c)(2)) relates to crude oil and condensate from facilities that do not file Forms PR or T-1, such as gas plants and disposal wells. The Commission makes no changes in response to this comment.

Subchapter A, Division 9- Miscellaneous Permits

Commission Shift expressed concern that the procedures for miscellaneous permits in Division 9 create loopholes. Commission Shift is also concerned that the District Director has authority to grant miscellaneous permits. The comments generally oppose the flexibility and discretion incorporated into the permitting process under Division 9 and request more transparency regarding the decisions and more detailed permit application requirements.

The Commission disagrees that the procedures in Division 9 create loopholes. The District Office staff is best positioned to evaluate and respond to emergency and minor permits. Technical Permitting staff do not have the appropriate resources to conduct reviews that have historically been completed by District Office staff. The nature of the permits in Division 9 requires the Commission to maintain flexibility and determine appropriate permit conditions based on the proposed activities. The Commission declines to adopt Commission Shift's suggestions to remove the permit types contemplated by Division 9.

Regarding Emergency Permits in §4.181, Commission Shift opposes the permit term of 30 days and suggests it be decreased to 15 days.

The Commission disagrees because it finds 30 days is appropriate in most circumstances. Emergency permits are rare and relate to extreme situations. Fifteen days is likely insufficient to allow the emergency to be addressed.

Regarding Pilot Programs under §4.185, Commission Shift requested the Commission clarify that pilot programs are limited to recycling by changing title to "Pilot Recycling Programs." The comments also stated pilot projects should not be exempt from Division 4-8 requirements. The comments suggested requiring notice and public input and setting metrics and goals for a project before issuing the permit. In addition, the Commission should require at least quarterly reporting, make reports publicly available, and prohibit these permits from continuing past five years without hearing and public input.

The Commission notes proposed §4.185(a) expressly states that the rule pertains to recycling activities. Pilot project permits include the elements of Divisions 4-8, where applicable. However, the nature of a pilot project, which is short term and with a limited waste volume, renders some of the requirements in Divisions 4-8 excessive. The Commission makes no changes in response to these comments.

Subchapter A, Division 10- Requirements for Oil and Gas Waste Transportation

Regarding Division 10, which addresses waste characterization, documentation, and transportation, Diamondback and TXOGA requested the Commission clarify (1) whether the operator may provide one general Waste Characterization Form for multiple facilities that share the same waste stream or waste type; and (2) what is the generator-assigned identifier.

The Commission agrees that the operator may provide one general Waste Characterization Form for multiple facilities that share the same waste stream or waste type. The generator-assigned identifier is the unique name that the generator uses to identify this particular waste stream. It should be specific enough to distinguish waste types (e.g., oil-based mud or water-based mud) but does not necessarily need to be specific to individual formations. However, the generator should give attention to limitations that may be carried with the waste stream. For example, synthetic drilling fluids should not be sent to recycling facilities that are not capable of processing the waste. The Commission will consider developing guidance to further clarify this and similar issues.

TIPRO, Diamondback, and TXOGA requested the Commission remove "estimated quantity of the waste" from §4.190(b)(1)(D) because that appears on the manifest as "type and volume of waste transported." These commenters also requested the Commission remove "domestic septage" and "rubbish" from list of example standard waste types because these wastes are regulated by the TCEQ.

The Commission agrees to remove "estimated quantity of the waste" from §4.190(b)(1)(D) but declines to remove "domestic septage" and "rubbish." Domestic septage and rubbish are merely optional waste profiles the operator may establish.

EPEC Energy, NESCO, and Commission Shift commented that process knowledge is not sufficient for waste characterization and so lab testing should be required.

The Commission disagrees. As stated above, process knowledge is sufficient to characterize most oil and gas waste that is subject to the RCRA exemption.

PBPA, TIPRO, Diamondback, and TXOGA requested whether electronic signatures will be accepted for the three signatures required by §4.191(b).

The Commission confirms that electronic signatures are allowed. The Commission notes this is addressed in §4.191(a)(2).

PBPA, TIPRO, Diamondback, and TXOGA also commented requesting a solution relating to signature requirements. They stated that the majority of produced water loads transported by truck to a receiver occur at un-staffed locations. Requiring a signature for every manifest will be overly burdensome at those un-staffed locations. The signature also adds little value. Diamondback and TXOGA requested that the Commission waive the signature requirement if the generator has entered into a contractual agreement with a transporter to haul the waste. PBPA and TIPRO asked that the signature requirement be removed.

The Commission notes that several comments request specific changes to the components of the manifest, waste profile form, or to the profile and manifest processes. For example, in addition to the comments above, Diamondback and TXOGA also asked for clarification regarding the identification number for midstream facilities, the Commission-assigned facility number, and the identifier for the facility to which waste is delivered. The Commission will begin to develop forms upon adoption of the rules but prior to the rules' effective date of July 1, 2025. The Commission will consider the commenters' suggestions related to specific profile and manifest requirements as it develops those forms and instructions. The Commission declines to remove the signature requirement altogether but will consider whether a contract that fulfills this requirement would be acceptable. The Commission also declines to make other changes to the lists of required profile and manifest elements (proposed in §4.190 (b)(1) and §4.191(b) respectively). These lists contain minimum requirements for the forms, so the Commission does not deem it necessary to amend the basic components in the rule based on the comments.

Regarding waste tracking in §4.191, NESCO recommended that facilities should be required to notify the Commission immediately if the facility refuses to accept a load of unauthorized waste. Similarly, Galatea Technologies and Waste Management requested additional requirements for how to handle and report discrepancies in manifests.

The Commission agrees and adopts §4.191 with new subsection (e) to require a commercial facility receiver that refuses to accept a load of waste that is not correctly characterized or manifested to notify Technical Permitting immediately. The notification shall include information necessary to identify the waste hauler and generator.

TXOGA, Diamondback, PBPA, TIPRO, and Deep Blue also commented on §4.191 requesting clarification regarding whether recycled produced water is subject to requirement of 4.191(d). The commenters note that recycled produced water is not considered a "waste."

The Commission concludes that produced water in a recycling system, as those systems are currently operated, is a waste. The Commission considers produced water a waste, though it agrees that a waste that is recycled ceases to be a waste when legitimately reused (e.g., when produced water is used in a downhole reuse activity). Generally, the Commission deems most of the current produced water treatment and recycling activities to be waste management. Produced water is not a waste when it is used in a downhole activity pursuant to prior §3.8(d)(7)(B) and new proposed §4.112. However, the management of treated produced water in pits and pipelines, and the potential for spills or other releases, is currently governed as a waste per applicable statutes and rules. Therefore, the Commission concludes that produced water in a recycling system is a waste. The Commission is open to reconsidering this understanding as the industry progresses such that other non-downhole uses of treated produced water become available.

TXOGA, Diamondback, PBPA, and TIPRO commented regarding §4.191(d), asking the Commission to allow documentation in addition to metering for oil and gas waste moved by pipeline. Heritage oil and gas wells and central tank batteries are not equipped with metering technology, but the oil and gas waste moved could be documented. Requiring metering would impose a cost on industry that has not been considered.

The Commission adopts §4.191(d) with a change to address this comment.

NESCO also requested the Commission require testing records, type of truck and associated volumes, records of waste receipts, and records of paint filter testing be kept for three years and made available to the Commission for review.

The Commission notes that proposed subsection (a) of §4.194 requires generators, waste haulers, and receivers to keep all waste profiles, manifests, and other documentation for a period of at least three years. The person keeping any records required by this section must make the records available to the Commission upon request. The Commission declines to make any changes in response to NESCO's comment.

The Commission proposed §4.192, Special Waste Authorization (adopted with the new title, "Trans-jurisdictional Waste Transfers") to provide a process for tracking oil and gas waste transported to be managed at appropriate TCEQ-regulated facilities and for certain TCEQ-jurisdictional waste transported to be managed at appropriate Commission-regulated facilities.

Waste Control Specialists (WCS) asked the Commission to clarify that receivers may receive waste from other receivers. WCS noted that generators often give their oil and gas NORM waste to another receiver who aggregates that waste prior to disposal.

The Commission adopts the definition of receiver in §4.110 with a change to address this comment.

TXOGA and Diamondback requested that §4.192 be removed because this process is sufficiently addressed in the Memorandum of Understanding (MOU) between the Commission and TCEQ. The proposed approval process will result in long wait times that may pose a risk to human health because of waste accumulation on site. Waste Control Specialists (WCS) also commented opposing a process that would require duplicate authorizations.

The Commission disagrees that §4.192 should be removed. It is important that the Commission know the disposition of waste under its jurisdiction. The Commission recognizes some waste may already have authorization for disposition at a TCEQ-regulated facility pursuant to the MOU in §3.30 of this title. However, the Commission needs to evaluate whether that waste achieves such disposition. Given the comments from TXOGA, Diamondback, and WCS, the Commission determines it is appropriate to adopt §4.192 with changes and delay the effective date to December 31, 2026. This will give the Commission and the TCEQ sufficient time to consider changes that will allow the Commission to track disposition of Commission-jurisdictional waste and ensure consistency with the MOU, which may require amendments consistent with adopted §4.192 and other rules adopted in this rulemaking.

Regarding §4.193, relating to Oil and Gas Waste Haulers, Commission Shift commented about the meaning of the term "incidental" in subsection (a). Commission Shift also suggested adding "at all times" in subsection (e)(10) to clarify spillage is never allowed, whether in transport or not. Further, Commission Shift suggested splitting inert waste and other wastes (asbestos, PCBs, and hazardous waste) into separate paragraphs.

The Commission notes that the "incidental" volume of waste cited in §4.193 is related to skim oil normally present in produced water or other oil and gas wastes. However, the Commission understands the term "incidental" may cause confusion or uncertainty and so that term is removed in adopted §4.193(a). The Commission also agrees with Commission Shift's suggested change in subsection (e)(10) and adopts that change. The Commission declines to separate inert waste and other wastes into different paragraphs because those wastes are excluded from §4.193.

Regarding §4.195, relating to Waste Originating Outside of Texas, Diamondback and TXOGA asked whether this only applies to trucked waste or if it applies to piped waste as well.

The Commission notes this applies to waste moved by surface vehicles only and adopts §4.195 with a change to clarify that application.

Commission Shift requested clarification regarding the term "notwithstanding" in §4.195 and whether the record keeping requirements apply to out of state waste.

The Commission agrees the term "notwithstanding" may cause confusion and makes changes to §4.195 accordingly.

Subchapter A, Division 11- Requirements for Surface Water Protection

Commission Shift submitted comments on §4.196, relating to Surface Water Pollution Prevention, and §4.197, relating to Consistency with the Texas Coastal Management Program.

Regarding §4.196, Commission Shift asked the Commission to clarify that all rules apply to activities on land that cause pollution of any state waters, whether inland, fresh, or offshore. Commission Shift also asked the Commission to specify that the requirements in these sections apply to all activities within Commission's jurisdiction, not just oil, gas, and geothermal.

The Commission adopts §4.196 with a change to include all activities under the Commission's jurisdiction. The Commission declines to add "on land" because this section is focused on Texas offshore waters and adjacent estuarian zones.

Regarding §4.197, Commission Shift asked why regulations regarding discharges were removed when the requirements of §3.8(j)(1)(B) and (j)(3)(B) were relocated to proposed new §4.197.

The Commission notes the regulations were removed because House Bill 2771 in 2019 removed the Commission's jurisdiction over all discharges.

The Commission appreciates the commenters who provided input on the proposed new rules in Subchapter A.

Subchapter B- Commercial Recycling

Chapter 4, Subchapter B governs commercial recycling activities and was originally adopted by the Commission in 2006. In this rulemaking, the Commission proposed amendment of numerous rules in Subchapter B.

Similar to their comments in Subchapter A, Diamondback and TXOGA asked the Commission to remove requirements for independent lab analyses and professional engineer certification of a lab report. They stated that some Commission-regulated facilities have onsite NELAP certified labs. Using an independent NELAP certified lab provides no additional benefit and causes unnecessary delays. Similarly, there is no value in having an engineer who does not perform the sampling or conduct the analysis certify the report.

The Commission declines to remove requirements for independent certified lab analysis and professional engineer certification. For permitted operations, the Commission has long required laboratory analytical results submitted to the agency to be collected by an independent certified laboratory. Similarly, geotechnical laboratory analysis should be overseen and certified by a Licensed Professional Engineer.

Regarding geosynthetic clay liners, Dr. Brownlow and Dr. Rogers stated that geosynthetic clay liners do not provide any significant impediment to fluid migration where the fluid is produced water-like with elevated salt concentrations. GCLs specifications are based on testing with distilled water.

The Commission agrees and adopts the following sections with changes to address the concerns with geosynthetic clay liners: §§4.219(b)(5), 4.232(b), 4.248(b)(1), 4.264(a). and 4.280(a)(1).

Sierra Club and Commission Shift commented regarding §4.272 and §4.288, which state that the Director will presume that an application meeting certain requirements does not present an unreasonable risk of pollution or threat to public health or safety with regard to siting, unless extraordinary circumstances indicate otherwise. The commenters asked that the provision be removed because applicants should be required to show their projects are safe. The responsibility should not fall to the public to disprove safety.

The Commission adopts §4.272 and §4.288 to remove the language quoted above in response to these comments.

Commission Shift noted generally that many of its comments expressed on Subchapter A apply to Subchapter B as well. These include suggestions to increase transparency and public participation, reduce director discretion, improve monitoring requirements, increase penalties, prevent revisions to applications during a hearing on the permit, increase setbacks, expand notice requirements, and require permits issued under prior rules to come into compliance with the amended rules by a specified date.

The Commission makes no changes to Subchapter B based on these comments and references its responses above to illustrate its position on these issues.

Finally, Sierra Club, 57 individuals, and Commission Shift commented regarding Subchapter B, Division 7, which applies to the Beneficial Use of Drill Cuttings. Generally, these commenters requested that the Commission remove Division 7 and study the issue more thoroughly before adopting rules. In the alternative, Commission Shift submitted comments suggesting several changes to Division 7.

Commission Shift requested that if Division 7 is adopted, the Commission at least remove the ability for processed drill cuttings to be used on county roads because this use goes beyond what the statute envisioned and does not set clear enough standards to ensure protection of public health and safety. Commission Shift also requested that the standards in proposed §4.301(b)(3)(A)-(B) apply to any proposed use of drill cuttings. Commission Shift commented regarding the definition of "legitimate commercial product," which was proposed in §4.204 and relates to Division 7. Commission Shift stated the term should ensure the use of legitimate commercial products is actually beneficial.

The Commission adopts Division 7 with changes to address these comments. First, the Commission removes the language in §4.301(b) relating to use of treated drill cuttings on county roads or as a concrete bulking agent, oil and gas waste pit disposal cover or capping material, treated aggregate, closure or backfill material, berm material, or construction. Revised §4.301 allows the Commission to approve a permit for the treatment and recycling for beneficial use of drill cuttings if the drill cuttings are used in a legitimate commercial product for the construction of oil and gas lease pads or oil and gas lease roads. The changes also contemplate permits for treated drill cuttings to be used in other legitimate commercial products, but only if the applicant can demonstrate the product meets the standards proposed in §4.301(b)(3)(A)-(B), which are adopted in §4.301(b)(2)(A)-(B). The Commission adopts an additional standard in §4.301(b)(2)(C), to require a demonstration that the product does not cause or contribute to the pollution of surface or subsurface water.

The Commission makes corresponding revisions to §4.302. The Commission also revises §4.302(b)(5) to require that the written report of the results of the trial run be prepared by a professional engineer licensed in Texas. This change is made in response to a comment from Commission Shift expressing concerns about the sufficiency of the trial run.

This concludes the description of comments and the Commission's response and recommended changes due to comments. The remaining paragraphs summarize the adopted rules.

The Commission adopts new Subchapter A to relocate and update the requirements in §3.8. Section 3.8 or "Statewide Rule 8" has existed in its current form since 1984 with only minor modifications since then. Expectations for environmental protection have evolved considerably over the past 40 years, and routine industry practices have changed significantly since the onset of shale extraction in the early 2000s. Within the last several years, additional industry growth, new technological advancements, and innovative solutions for resource development challenged the flexibility of these historic regulations. For example, there is a rapidly evolving need to encourage the treatment and recycling of produced water for beneficial uses within the oil and gas industry and for novel beneficial uses outside of the industry. The Legislature has directed the Commission to encourage fluid oil and gas waste recycling (House Bill 3516, 87th Legislature, 2021), and it has also created the Texas Produced Water Consortium (Senate Bill 601, 87th Legislature, 2021) to make recommendations to the Legislature on issues related to this potential activity. Already, many exploration and production operators and water midstream service providers are investing in infrastructure and pilot studies to assess the economic, logistical, environmental, and practical possibilities of produced water recycling. The Commission's rules need to address and support these developments.

In addition to House Bill 3516, House Bill 2201 (87th Legislature, 2021) directed the Commission to adopt rules governing permissible locations for pits used by commercial oil and gas disposal facilities and Senate Bill 1541 (85th Legislature, 2017) required the Commission to incorporate criteria for beneficial uses of recycled drill cuttings. The Commission adopts new requirements in Subchapter A to address House Bill 2201 and adopts new rules in Subchapter B to address the requirements of Senate Bill 1541.

Many of the requirements from Section 3.8 are incorporated into new rules in Subchapter A of Chapter 4. In some sections, the Commission allows compliance to be achieved by a future date after the new rules and amendments to Chapter 4 have become effective. The new rules and amendments go into effect July 1, 2025, which is approximately six months after the date the rules are adopted. Many provisions are adopted with a later effective date of six months to one year from July 1, 2025, to provide additional time for compliance. Effective dates are reflected in the following sections: 4.109, 4.113, 4.115, 4.121, 4.122, 4.123, 4.140, 4.170, 4.192, 4.202, 4.266, 4.273, 4.282, and 4.289.

Division 1 of Subchapter A addresses general requirements. New §4.101 communicates the subchapter's purposes - to prevent pollution and protect the public health, public safety, and the environment within the scope of the Commission's authority. Section 4.101 also clarifies that certain other wastes generated by activities under the Commission's jurisdiction may be managed in accordance with Subchapter A as long as the wastes are nonhazardous and chemically and physically similar to oil and gas wastes. The list of activities that may generate waste under the Commission's jurisdiction includes activities such as brine mining and injection wells and Class VI carbon sequestration program wells.

The Commission adopts §4.102 to require generators of oil and gas waste to characterize the waste. Generally, process knowledge may be used to categorize the waste material in accordance with the categories listed in the definition of oil and gas waste in §4.110. However, laboratory analysis of waste may be required for waste generated at a commercial facility or transferred from one commercial facility to another.

The Commission adopts §4.103 to specify waste management methods that are prohibited. Generally, a Commission authorization or permit to manage waste is required except in three instances: (1) as authorized by §4.111 (relating to Authorized Disposal Methods for Certain Wastes); (2) as authorized by §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste); or (3) by underground injection for disposal permitted pursuant to §3.9 of this title (relating to Disposal Wells) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs). Recycling oil and gas wastes without a permit is prohibited unless the recycling is conducted pursuant to §4.112 (relating to Authorized Recycling).

New §4.104 clarifies how the Commission will implement its authority over activities for which other regulatory agencies have related jurisdiction.

New §4.106 notifies persons required to comply with Subchapter A that fees and corresponding surcharges may apply pursuant to §3.78 (relating to Fees and Financial Security Requirements).

New §4.107 contains the guidelines for assessing penalties for violations of Subchapter A.

The Commission adopts §4.108 to ensure all required filings are made electronically if the Commission has provided an electronic version of a form or an electronic filing system. The section also clarifies that the standards for electronic filings are the same as those for filings in other formats.

New §4.109 allows applicants or permittees to request exceptions to the requirements of Subchapter A.

New §4.110 contains the definitions for Chapter 4, including Subchapters A and B.

New Division 3 of Subchapter A relates to Operations Authorized by Rule. The rules in this division allow operators to conduct certain waste management activities through a "permit by rule" system - the operator is not required to obtain a permit through a permit application and review process. Instead, the operator is authorized to engage in the activity as long as the applicable rule requirements are met.

New §4.111 provides that certain wastes may be disposed of without first obtaining a permit from the Commission if the disposal complies with the requirements of the section.

Similarly, §4.112 allows recycling without a permit in certain instances.

New §4.113 specifies types of waste management pits that may be operated without a permit if they comply with the requirements of §4.113. Subsection (c) provides instructions for pits authorized under the predecessor rule, §3.8. Most types of pits authorized by §3.8 and compliant with that section prior to July 1, 2025, may continue to operate unless they cause pollution. However, basic sediment pits, flare pits, and other pits not listed as authorized pits in §4.113 must obtain a permit or be closed in accordance with new Subchapter A by July 1, 2026. Also, as discussed in the paragraphs below regarding §4.114 and §4.115, new Subchapter A alters terminology and requirements related to non-commercial fluid recycling. New §4.113(c)(3) states that each non-commercial fluid recycling pit shall be registered and supported by financial security by January 1, 2026, or the pit must be closed.

New §4.113(d) contains new requirements for registration of all authorized pits.

The Commission adopts §4.114 to specify requirements for Schedule A authorized pits. Authorized pits (pits "permitted by rule") are divided into two categories: Schedule A and Schedule B. Each category imposes different requirements.

The Commission adopts §4.115 to create new terminology and requirements for produced water recycling pits, which are classified as Schedule B Authorized Pits.

The Commission adopts additional requirements for Schedule B authorized pits because these pits are generally larger in size, manage a larger volume of waste, and are operated for a longer time compared to Schedule A authorized pits. Subsection (c) provides additional time for compliance for non-commercial fluid recycling pits authorized prior to July 1, 2025. Under new §4.115, these pits continue to be authorized, but must be registered and secured by a performance bond or other form of financial security as required by §4.115 by January 1, 2026.

Division 4 of Subchapter A contains the general requirements for all other waste management activities that are not authorized under Division 3. These waste management activities require a permit before the operator may conduct the activity. Many of the requirements in Divisions 4 through 9 are similar to permit conditions in permits currently issued by the Commission. The Commission adopts that these standards be incorporated into Divisions 4 through 9, as applicable. The Commission also adopts additional standards for permitted facilities to ensure the rules address the complex needs and requirements of contemporary waste management and environmental protection practices.

New §4.120 identifies the Commission's purpose in permitting -- the Commission will not issue a permit if the Commission determines the proposed activity will result in: (1) the endangerment of human health or the environment; (2) the waste of oil, gas, or geothermal resources; or (3) the pollution of surface or subsurface water. New §4.120 also clarifies that all permitted waste management activities are subject to financial security requirements. Finally, §4.120(e) provides a list of waste management activities governed by Subchapter A and specifies which division applies to each activity. For example, permitted pits must comply with the requirements in Division 6 in addition to the requirements of Division 4, which apply to all waste management activities that must obtain a permit.

The Commission adopts §4.121 to incorporate a permit term for all waste management permits, which shall be not more than five years.

New §4.122 outlines requirements for permit renewals, transfers, and amendments, while new §4.123 contains requirements for permit modification, suspension, or termination. A permit issued under new Subchapter A or pursuant to §3.8 prior to July 1, 2025, may be modified, suspended, or terminated by the Commission for good cause after notice and opportunity for a hearing.

The Commission adopts §4.124 to specify permit application filing requirements and contents.

Section 4.125 addresses notice requirements for all permitted facilities.

The Commission adopts §4.126 to outline the location and real property information required to be included in the permit application. New §4.127 contains the requirements for engineering and geologic information submitted in the permit application.

The Commission adopts §4.128, which contains requirements related to the facility's design and construction. Section 4.128 includes requirements for information to be included in the permit application as well as requirements for the constructing the facility. Section 4.129 includes requirements for information to be included in the permit application relating to the facility's operation, as well as requirements for operating the facility once permitted.

Section 4.130 specifies the requirements for retaining records and submitting periodic reports to the Commission.

The Commission adopts §4.131 to explain the factors the Commission will consider in determining whether groundwater monitoring is required when groundwater is present within 100 feet below the ground surface.

New §4.132 contains requirements related to closure.

The Commission adopts §4.134, which states that Technical Permitting reviews applications filed under Subchapter A in accordance with §1.201 (relating to Time Periods for Processing Applications and Issuing Permits Administratively).

New §4.135 contains the process for a hearing when a permit application is denied, a timely protest to the application is received, or when the applicant disagrees with permit conditions required by the Director.

Divisions 5 through 9 contain requirements for certain waste management activities. Operators of facilities governed by these divisions must comply with the requirements set forth in the division in addition to the requirements set forth in Division 4. Facilities may be governed by more than one division in addition to the general requirements of Division 4. For example, a commercial disposal pit would be subject to the requirements of Division 4 and the requirements of Division 5 (relating to Additional Requirements for Commercial Facilities) and the requirements of Division 6 (relating to Additional Requirements for Permitted Pits). This intent is clarified in §4.140, §4.150, and §4.160, which state that in addition to the requirements of the applicable division, the permittee shall comply with Division 4 and any other sections of Subchapter A applicable to the permittee's management of oil and gas wastes.

Division 5 contains the additional requirements for commercial facilities. Section 4.140(b) recognizes that new definitions and requirements in Subchapter A may alter a facility's classification such that a facility considered non-commercial prior to July 1, 2025 may be considered commercial after that date (the estimated effective date of the new rules). Such facilities are required to comply with the requirements of Division 5 or request an exception on or before July 1, 2026.

In addition to the notice requirements outlined in §4.125, the Commission adopts that commercial facilities provide notice by publication.

Additional operating requirements for commercial facilities are in §4.142. These requirements include a detailed waste acceptance plan, a site-specific spill control plan, and a stormwater management plan.

Division 6 specifies additional requirements for permitted pits. As mentioned above, §4.150(a) clarifies that in addition to the requirements of Division 6, the permittee shall comply with Division 4 and Division 5. Subsection (b) states that if at any time a pit no longer meets the requirements for authorized pits under §4.113, the operator of the pit shall apply for a pit permit pursuant to the requirements of Division 6.

Section 4.151(a) contains information that must be included in a pit permit application in addition to the information required by §4.128. Pits permitted pursuant to Subchapter A are also subject to additional requirements that the Director determines are necessary to prevent pollution.

The Commission adopts §4.152 to require a permittee governed by Division 6 to implement a monitoring plan in which the permittee routinely monitors the integrity of the pit liner.

In accordance with House Bill 2201 from the 87th Legislative Session, the Commission adopts §4.153 to incorporate siting requirements for commercial disposal pits. Under subsection (a)(1), the application for a pit at a commercial disposal facility shall include documentation of a good faith investigation of the 10-year flooding history of the property to determine whether the facility is located in a flood-prone area.

Closure requirements for all permitted pits are adopted in §4.154.

Division 7 applies to permits for landfarming and landtreating. Section 4.160 clarifies that the requirements in Division 4 must be adhered to in addition to the requirements of Division 7.

The Commission adopts §4.161 and §4.162 to require additional information in applications for landfarming and landtreating. The Commission adopts §4.163 to require monitoring of three soil zones in each active cell.

Section 4.164 contains closure requirements specific to landfarming and landtreating permits.

Division 8 describes the requirements applicable to permitted reclamation plants and is substantively similar to current §3.57 (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials), which is amended concurrently with the new rules in Subchapter A. The Commission adopts two notable changes to its regulatory requirements for reclamation plants. First, new §4.170 and §4.171 limit a reclamation plant permit to a five-year term. Second, new §4.171(b) allows reclamation plant permits to be transferred, renewed, or amended in accordance with §4.122. Section 4.170(a)(7) states that reclamation plant permits issued under §3.57 before July 1, 2025 expire five years from July 1, 2025 but may be renewed pursuant to §4.122.

Division 9 specifies requirements for emergency permits (§4.181), minor permits (§4.182), and permitted recycling (§4.184) that are generally consistent with the requirements for these permits contained in current §3.8. However, the Commission adopts new §4.185 to allow the approval of pilot projects for certain activities, such as the recycling of treated produced water.

The Commission adopts Division 10 to incorporate requirements for transportation of oil and gas waste, including new regulations relating to oil and gas waste characterization and documentation. As specified in §4.102, the generator of oil and gas waste is responsible for characterizing the waste. Section 4.190(a) incorporates that requirement and also specifies that the generator must document the waste characterization using a Waste Profile Form prior to transportation.

New §4.191 requires oil and gas waste that is transported by vehicle from the location where it is generated to another facility to either be accompanied by a paper manifest or be documented and tracked by an electronic manifest system. Section 4.191(b) specifies the required components of a manifest.

Section 4.192 provides a process for waste transfers made across jurisdictional authorities to be reported to the Commission beginning December 31, 2026. Section 4.193 incorporates requirements for oil and gas waste haulers.

Section 4.194 requires all generators, waste haulers, and receivers to retain waste profiles, manifests and other documentation for at least three years and provide such records to the Commission upon request.

The Commission adopts §4.195 to address oil and gas waste generated outside the State of Texas and transported into Texas for management.

Division 11 includes new §4.196 and §4.197, which are mostly unchanged from current §3.8(e) and §3.8(j). These sections are incorporate the requirements from §3.8 into the new rules in Subchapter A.

Amendments to Subchapter B

The Commission also adopts conforming amendments to Subchapter B of Chapter 4. Many of the amendments replace references to §3.8 with the applicable provision now included in new Subchapter A. Other amendments ensure consistency between new Subchapter A and existing Subchapter B. Amendments in various sections update Division and Department names and ensure terms are used consistently throughout the Subchapter. In addition, amendments incorporate legislative requirements imposed by House Bill 3516 (87th Legislature, 2021) and Senate Bill 1541 (85th Legislature, 2017).

The following sections are amended to remove references to §3.8 or to make other non-substantive updates: §§4.203, 4.207, 4.209, 4.218, 4.220, 4.222, 4.223, 4.239, 4.242, 4.243, 4.245, 4.250, 4.251, 4.255, 4.258, 4.259, 4.261, 4.267, 4.277, 4.287, and 4.293.

The Commission adopts amendments in §4.201 to ensure consistency with the purpose stated in new §4.101.

Amendments in §4.202 replace references to §3.8 with references to new Subchapter A of Chapter 4. Amendments in subsection (h) outline requirements for permits issued prior to the effective date of the amendments, which is July 1, 2025.

Amendments in §4.204 clarify that the definitions in new §4.110 of Subchapter A, relating to Definitions, apply in Subchapter B as well. Terms that already appear in new §4.110 are removed from §4.204 to reduce confusion. The terms amended or added to §4.204 are terms unique to Subchapter B or terms for which the meaning is altered for purposes of Subchapter B.

Amendments in §4.208(c) require that all chemical laboratory analyses be performed using the appropriate Environmental Protection Agency (EPA) method or standard methods by an independent National Environmental Laboratory Accreditation Program certified laboratory.

The Commission adopts to amend §4.211 to incorporate new penalty guidelines and standard penalty amounts for violations of rules in Subchapter B.

Amendments in §4.212 update requirements for filing an application for on-lease solid oil and gas waste commercial recycling.

Amendments in §4.213 expand the scope of subsection (b) to contemplate geologic work products and allow such products to be sealed by a professional engineer or geoscientist licensed in Texas. Similar amendments are adopted in §§4.231, 4.247, 4.263, and 4.279.

Amendments in §4.219 remove outdated language that is no longer applicable and update location requirements for on-lease commercial solid oil and gas waste recycling to be consistent with Commission practices.

In addition to minor amendments to ensure consistent use of terms, amendments in §4.221 require additional information to be included in the written report of the trial run.

The Commission adopts amendments to §4.224 to require an operator to include the facility identification number assigned by Technical Permitting in the operator's application for a permit renewal. Facility identification numbers will assist Technical Permitting in identifying facilities that may have several different types of permits.

Amendments in §4.230 update requirements for filing an application for off-lease or centralized commercial solid oil and gas waste recycling.

The Commission adopts §4.232 with amendments to require a United States Geological Survey topographic map or an equivalent topographic map to be included with the permit application. Similar siting requirements are in §4.248 for stationary commercial solid oil and gas waste recycling, in §4.264 for off-lease commercial fluid recycling, and in §4.280 for stationary commercial fluid recycling.

Amendments in §4.234 allow the Technical Permitting Section to waive the requirement that a permit application include a plan for the installation of monitoring wells. Similarly, the Commission adopts amendments in §4.241(b), §4.257(b), §4.273(b), and §4.289(b) to provide the Technical Permitting Section discretion to evaluate the facts of the specific permit application and determine whether certain requirements are appropriate.

The Commission adopts amendments to §4.238 to ensure notice requirements in Subchapter B are consistent with notice requirements in new Subchapter A. The same amendments are adopted in §§4.254, 4.270, and 4.286.

Amendments in §4.240 remove outdated language that no longer applies and clarify certain factors the Commission will consider in assessing potential risk associated with an off-lease centralized commercial solid oil and gas waste recycling facility.

Amendments in §4.246 update requirements for filing an application for a stationary commercial solid oil and gas waste recycling facility.

Amendments in §4.254 ensure that notice recipients receive instructions for filing notice electronically if the Commission implements an electronic means for filing protests.

Amendments in §4.256 remove outdated language that is no longer applicable and update location requirements for a stationary commercial solid oil and gas waste recycling facility.

Amendments in §4.262 update requirements for filing an application for off-lease commercial recycling of fluid. Amendments in subsection (d) implement House Bill 3516 (87th Legislature, 2021), which requires the Commission to approve or deny a complete application that does not include a request for an exception not later than the 90th day after the date the complete application was received by the Commission, unless a protest is filed. Further, if the Commission does not approve or deny the application before the 90th day, the permit application is considered approved, and the applicant may operate under the terms specified in the application for a period of one year.

The Commission adopts amendments in §4.263 to incorporate additional requirements for engineering, geological, and other information submitted in an application for an off-lease commercial fluid recycling permit.

Section 4.264 is amended to include House Bill 3516's requirement that the Commission establish minimum siting standards for fluid recycling pits.

New language in §4.266 incorporates requirements from House Bill 3516.

Amendments in §4.268 add a requirement that the sampling plan submitted with the permit application ensures compliance with reuse requirements in the permit in addition to other permit conditions.

Amendments in §4.269 comply with House Bill 3516's requirement that the Commission adopt rules establishing uniform standards for estimating closure costs. The requirements for closure cost estimates (CCEs) in §4.269 are consistent with the CCE standards for commercial facilities permitted under Subchapter A.

In addition to the minor updates described above, the Commission adopts to amend §4.273 to add new subsections (f), (g), and (h). Subsection (h) requires that any pit associated with an off-lease commercial fluid recycling facility permitted after July 1, 2025, shall comply with the requirements of §4.265(a).

The Commission adopts new requirements in §4.274(e) to prohibit accumulation of oil on top of produced or treated water stored in the tanks and pits.

New requirements for operating an off-lease commercial fluid recycling facility are in §4.275(a) and (c). Existing language is renumbered as subsection (b). The Commission also adopts a figure in subsection (a)(6), which contains the required parameters for sampling.

New language in §4.276 replaces the minimum permit provisions for closure.

Amendments in §4.278 update requirements for filing an application for a stationary commercial fluid recycling facility.

The Commission adopts amendments in §4.279 to incorporate additional requirements for engineering, geological, and other information submitted in an application for a stationary commercial fluid recycling permit.

Section 4.280 is amended to include House Bill 3516's requirement that the Commission establish minimum siting standards for fluid recycling pits.

New language in §4.282 incorporates requirements from House Bill 3516. Subsection (a) establishes design and construction standards for pits at stationary commercial fluid recycling facilities. Subsection (a)(5) contains new liner requirements for such pits permitted after July 1, 2025.

Amendments in §4.283 clarify that the required waste acceptance plan shall identify specific types of oil and gas wastes and provides examples such as hydraulic fracturing flowback fluid and produced water.

Amendments in §4.284 add a requirement that the sampling plan submitted with the permit application ensures compliance with reuse requirements in the permit in addition to other permit conditions. Additionally, the application shall include a plan for monitoring groundwater based on the subsurface geology and hydrogeology.

Amendments in §4.285 conform to §4.269 and comply with House Bill 3516's requirement that the Commission adopt rules establishing uniform standards for estimating closure costs. The requirements for closure cost estimates (CCEs) are also consistent with the CCE standards for commercial facilities permitted under Subchapter A.

In addition to the minor updates described above, the Commission adopts to amend §4.289 to add new subsections (f), (g), and (h). Subsection (h) requires that any pit associated with a stationary commercial fluid recycling facility permitted after July 1, 2025, shall comply with §4.282(a).

The Commission adopts new requirements in §4.290(e) to prohibit accumulation of oil on top of produced or treated water stored in the tanks and pits.

New requirements for operating a stationary commercial fluid recycling facility are in §4.291(a) and (c). Existing language is renumbered as subsection (b).

New language in §4.292 replaces the minimum permit provisions for closure.

Finally, the Commission adopts new rules in Subchapter B, Division 7 (relating to Beneficial Use of Drill Cuttings) to satisfy requirements of Senate Bill 1541 (85th Legislature, 2017). Senate Bill 1541 instructed the Commission to adopt criteria for beneficial uses to ensure that a beneficial use of recycled drill cuttings is at least as protective of public health, public safety, and the environment as the use of an equivalent product made without recycled drill cuttings. Section 4.301 includes requirements for treatment and recycling for beneficial use of drill cuttings. The requirements in §4.301 must be met in addition to the requirements of Divisions 3 and 4 of Subchapter B, which relate to Requirements for Off-Lease or Centralized Commercial Solid Oil and Gas Waste Recycling, and Requirements for Stationary Commercial Solid Oil and Gas Waste Recycling Facilities, respectively.

Section 4.302 includes requirements for showing there is a demonstrated commercial market for the treated drill cuttings.

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

SUBCHAPTER A. OIL AND GAS WASTE MANAGEMENT

DIVISION 1. GENERAL

16 TAC §§4.101 - 4.104, 4.106 - 4.109

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.101. Prevention of Pollution.

(a) No person conducting activities subject to regulation by the Railroad Commission of Texas may cause or allow pollution of surface or subsurface water in the state.

(b) 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 minimum permitting, operating, monitoring, and closure standards and 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.

(c) 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.

(d) Hazardous waste as defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste) shall be managed in accordance with the provisions of §3.98 of this title.

(e) Used oil as defined in §3.98 of this title shall be managed in accordance with the provisions of 40 Code of Federal Regulations (CFR), Part 279.

§4.103. Prohibited Waste Management Methods.

(a) Unless authorized by this subchapter, no person may manage oil and gas wastes without obtaining a permit to manage such wastes, except for the following methods:

(1) as authorized by §4.111 of this title (relating to Authorized Disposal Methods for Certain Wastes);

(2) as authorized by §3.91 of this title (relating to Cleanup of Soil Contaminated by a Crude Oil Spill);

(3) as authorized by §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste); or

(4) by underground injection for disposal permitted pursuant to §3.9 of this title (relating to Disposal Wells) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs).

(b) The discharge of any waste under the jurisdiction of the Commission into any surface water defined under §4.110 of this title (relating to Definitions) is prohibited unless such discharge is authorized by and conducted in accordance with a Texas Pollutant Discharge Elimination System (TPDES) permit or authority issued by the Texas Commission on Environmental Quality (TCEQ) or another regulatory agency with jurisdiction over discharge of oil and gas wastes.

(c) No person may maintain or use any pit for storage of oil, oil products, or oil by-products.

(d) Except as authorized by this subchapter, no person may maintain or use any pit for storage of oil field fluids or for storage or disposal of oil and gas wastes without obtaining a permit to maintain or use the pit.

(e) Except as expressly provided by §3.30 of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)), no person may dispose of oil and gas wastes at a facility not under the jurisdiction of the Commission unless the Director expressly authorizes such disposal in writing.

(f) Except for those recycling methods authorized for certain wastes by §4.112 of this title (relating to Authorized Recycling), no person may recycle any oil and gas wastes by any method without obtaining a permit.

§4.104. Coordination Between the Commission and Other Regulatory Agencies.

(a) The Commission and TCEQ have adopted by rule a Memorandum of Understanding stating how the agencies will implement the division of jurisdiction over wastes. The MOU is adopted in §3.30 of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(b) Activities authorized or permitted by this subchapter may be subject to rules and regulations promulgated by the United States Environmental Protection Agency under the federal Clean Air Act or the TCEQ under the Texas Clean Air Act. The applicant shall obtain any required authority from other regulatory agencies prior to the receipt of waste authorized under this subchapter and provide evidence of such authority to the Commission upon request.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 17, 2024.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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Proposal publication date: August 30, 2024
For further information, please call: (512) 475-1295

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DIVISION 2. DEFINITIONS

16 TAC §4.110

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.110. Definitions.

The following words and terms when used in this chapter shall have the following meanings unless the context clearly indicates otherwise.

(1) 25-year, 24-hour rainfall event--The maximum 24-hour precipitation event, in inches, with a probable recurrence interval of once in 25 years, as defined by the National Weather Service and published by the National Oceanic and Atmospheric Administration for the county in which the waste management activity is occurring.

(2) 100-year flood--A flood that has a 1.0% or greater chance of occurring in any given year.

(3) 100-year flood plain--The lowland and relatively flat areas adjoining inland and coastal waters, including flood-prone areas of offshore islands, that are inundated by the 100-year flood, as determined from maps or other data from the U.S. Army Corps of Engineers or the Federal Emergency Management Agency (FEMA).

(4) Action leakage rate--The calculated volume of waste liquid that has bypassed the primary liner into the leak detection layer at a rate of gallons per acre per day that if exceeded indicates failure of the primary liner.

(5) Active cell--A waste management unit that has received oil and gas waste and has not completed closure.

(6) Active life--The period of time beginning when a waste management unit first receives waste and ending when closure of the waste management unit is complete.

(7) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, injection wells, disposal wells, or geothermal resource wells;

(B) the production of oil or gas or geothermal resources, including activities associated with:

(i) the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the Commission to regulate the production of oil or gas or geothermal resources;

(iii) the drilling of seismic holes and core holes subject to the jurisdiction of the Commission to regulate the exploration, development, and production of oil or gas or geothermal resources;

(iv) gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(v) any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in the Texas Natural Resources Code §91.173;

(vi) any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in the Texas Natural Resources Code §91.201; and

(vii) the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the Commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the management of oil and gas waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph, except for waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency (EPA) pursuant to the federal Solid Waste Disposal Act, as amended (42 USC §6901, et seq.).

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

(9) Aquifer--A geological formation, group of formations, or portion of a formation capable of yielding significant quantities of groundwater to wells or springs.

(10) ASTM--ASTM International (successor to the American Society for Testing and Materials).

(11) Authorized--An activity that is permitted or allowed by a rule.

(12) Authorized pit--A reserve pit, mud circulation pit, completion/workover pit, makeup water pit, fresh mining water pit,

water condensate pit, or produced water recycling pit that is permitted by rule and described and operated in accordance with Division 3 of this subchapter (relating to Operations Authorized by Rule).

(13) Basic sediment--A mixture of crude oil or lease condensate, water, sediment, and other substances or hydrocarbon-bearing materials that are concentrated at the bottom of tanks and pipeline storage tanks (also referred to as "basic sediment and water" or "tank bottoms").

(14) Brine pit--A pit used for storage of brine in connection with the solution mining of brine, the operation of an underground hydrocarbon storage facility, or other activities associated with oil and gas exploration, development, storage or production that involve the creation or use of a salt cavern.

(15) Buffer zone--The minimum distance allowed between a waste management unit and another feature, such as a property boundary, surface water, or water well.

(16) Carrier--A person who is permitted to transport oil and gas wastes. A carrier of another person's oil and gas wastes may be a generator of its own oil and gas wastes. A permitted waste hauler is a carrier.

(17) Coastal Management Program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at 31 Texas Administrative Code Chapters 26 through 29.

(18) Coastal Natural Resource Area (CNRA)--One of the following areas defined in Texas Natural Resources Code §33.203: coastal barriers, coastal historic areas, coastal preserves, coastal shore areas, coastal wetlands, critical dune areas, critical erosion areas, gulf beaches, hard substrate reefs, oyster reefs, submerged land, special hazard areas, submerged aquatic vegetation, tidal sand or mud flats, water in the open Gulf of Mexico, and water under tidal influence.

(19) Coastal waters--Waters along the coast under the jurisdiction of the State of Texas, including tidal influence and waters of the open Gulf of Mexico.

(20) Coastal zone--The area within the boundary established in 31 Texas Administrative Code §27.1 (relating to Coastal Management Program Boundary).

(21) Commercial facility--A facility permitted under Division 4 of this subchapter (relating to Requirements for All Permitted Waste Management Operations), whose owner or operator receives compensation from others for the management of oil field fluids or oil and gas wastes and whose primary business purpose is to provide these services for compensation.

(22) Commission--The Railroad Commission of Texas.

(23) Completion/workover pit--A pit used for storage or disposal of spent completion fluids and solids, workover fluids and solids, and drilling fluids and solids, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed, worked over, or plugged.

(24) Contact stormwater--Stormwater that has come into contact with any amount of oil and gas wastes or areas that contain or have contained oil and gas wastes. See also "Non-contact stormwater" and "Stormwater."

(25) Container--A means of primary containment used for the management of oil and gas waste such as a pit, sump, tank, vessel, truck, barge, or other receptacle.

(26) Critical area--A coastal wetland, an oyster reef, a hard substrate reef, submerged aquatic vegetation, or a tidal sand or mud flat as defined in Texas Natural Resources Code §33.203.

(27) Dewater--To remove free liquids from a media such that the remaining material passes a Paint Filter Liquids Test (EPA Method 9095B, as described in "Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods," EPA Publication Number SW-846). See also "Free liquids".

(28) Director--The Director of the Oil and Gas Division or the Director's delegate.

(29) Discharge--To allow a liquid, gas, or other substance to flow out from where it has been confined.

(30) Disposal--The act of conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, dumping, placing, abandoning, landfarming, allowing seepage, or causing or allowing any such act of disposal of any oil field fluid, oil and gas waste, or other substance or material subject to regulation by the Commission.

(31) Disposal pit--A pit used for the permanent storage of oil and gas waste.

(32) District Director--The Director of the Commission district where the management, disposal, or recycling of oil and gas wastes is located or the District Director's delegate.

(33) District Office--The Commission District Office in the Commission district where the waste management, disposal, and/or recycling is located.

(34) Drill cuttings--Bits of rock or soil cut from a subsurface formation by a drill bit during the process of drilling an oil or gas well or other wells within the Commission's jurisdiction and lifted to the surface by means of the circulation of drilling mud. The term includes any associated sand, silt, drilling fluid, spent completion fluid, workover fluid, debris, water, brine, oil scum, paraffin, or other material cleaned out of the wellbore.

(35) Drilling fluid--Any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill boreholes into the earth.

(36) Electrical conductivity--A numerical expression of the ability of a material to carry a current, normally expressed in millimhos/centimeter (the reciprocal of resistivity). It is frequently used to estimate salinity in terms of total dissolved solids. In soil analysis, electrical conductivity may be used as one measure to evaluate a soil's ability to sustain plant growth.

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

(38) Facility--A site that shares a common area, common access, and a common purpose where oil field fluids or oil and gas wastes are managed. It may include one or more waste management units, may include permitted or authorized activities, and may be designated as either commercial or non-commercial.

(39) Free liquids--Liquids which readily separate from the solid portion of a waste under ambient temperature and pressure.

(40) Freeboard--The vertical distance between the top of a pit or berm and the highest point of the contents of the pit or berm.

(41) Fresh mining water pit--A pit used in conjunction with a brine mining injection well for storage of fresh water used for solution mining of brine.

(42) Generator--A person that generates oil and gas wastes.

(43) Geomembrane--An impermeable polymeric sheet material that is impervious to liquid and gas if it maintains its integrity and is used as an integral part of an engineered structure designed to limit the movement of liquid or gas in a system.

(44) Geotextile--A sheet material that is less impervious to liquid than a geomembrane but more resistant to penetration damage, and is used as part of an engineered structure or system to serve as a filter to prevent the movement of soil fines into a drainage system, to provide planar flow for drainage, to serve as a cushion to protect geomembranes, or to provide structural support.

(45) Groundwater--Subsurface water in a zone of saturation.

(46) Hydrocarbon condensate--Hydrocarbon liquids that condense from a natural gas stream.

(47) Inert oil and gas waste--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, synthetic liners, fiberglass, soil, dirt, clay, sand, gravel, brick, and trash. The term excludes asbestos or asbestos-containing waste, and oil and gas naturally occurring radioactive material (NORM) waste.

(48) Karst terrain--An area where karst topography, with its characteristic surface and/or subterranean features, is developed principally as the result of dissolution of limestone, dolomite, or other soluble rock. Characteristic physiographic features present in karst terrains include, but are not limited to, sinkholes, sinking streams, caves, large springs, and blind valleys.

(49) Land application--A method for the permanent disposition of low-chloride aqueous oil and gas waste by which the liquid waste is applied directly to the ground surface in a controlled manner via sprinkler or other irrigation systems without tilling or mixing with the native soils and without runoff to surface water or infiltration to groundwater.

(50) Landfarming--An authorized or permitted waste management practice in which low chloride, water-based drilling fluids, or oil and gas wastes are mixed with, or tilled into, the native soils in such a manner that the waste will not migrate from the authorized or permitted landfarming cell.

(51) Landfarming cell--The bermed area into which oil and gas waste is applied to the land and includes landfarming and landtreatment cells.

(52) Landtreating--An authorized or permitted waste management practice in which oil-based drilling fluids, oil impacted soils, and oil and gas wastes are mixed with or tilled into the native soil to degrade oil, grease, or other organic wastes through biological processes and in such a manner that the waste will not migrate from the authorized or permitted landtreatment cell.

(53) Leak detection system--A system used to detect leaks below the liner of pits.

(54) Liner--A continuous layer of impervious materials, synthetic or natural, beneath and on the sides of a pit that restricts or prevents the downward or lateral release or migration of oilfield fluids or oil and gas wastes.

(55) Makeup water pit--A pit used in conjunction with a drilling rig, completion operations, or a workover for storage of water used to make up drilling fluid or completion fluid.

(56) Manage or management of oil and gas waste--The receiving, handling, storage, treatment, processing, transportation, reclamation, recycling, and/or disposal of oil and gas wastes.

(57) Manifest--An electronic or paper document used to track shipments of oil and gas waste that is authenticated by all parties (the generator, carrier, and receiver) in the transfer of oil and gas waste, and contains information on the waste type, source, quantity, and instructions for handling.

(58) Mined brine--Brine produced from a brine mining injection well by solution of subsurface salt formations. The term does not include saltwater produced incidentally to the exploration, development, and production of oil or gas or geothermal resources.

(59) Mud circulation pit--A pit used in conjunction with drilling rig for storage of drilling fluid currently being used in drilling operations.

(60) Natural gas or natural gas liquids processing plant--A plant whose primary function is the extraction of natural gas liquids from field gas, the fractionation of natural gas liquids, and the production of pipeline-quality gas for transportation by a natural gas transmission pipeline. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment shall be considered a component of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids.

(61) Naturally occurring radioactive material (NORM)--Naturally occurring materials not regulated under the Atomic Energy Act whose radionuclide concentrations have been increased by or as a result of human practices. NORM does not include the natural radioactivity of rocks or soils, or background radiation, but instead refers to materials whose radioactivity is concentrated by controllable practices (or by past human practices). NORM does not include source, byproduct, or special nuclear material.

(62) Non-commercial facility--A facility authorized or permitted under this chapter that is not a commercial facility as defined in paragraph (21) of this section.

(63) Non-contact stormwater--Stormwater that, by design or direction, has not come into contact with any oil or gas wastes and is not otherwise designated as contact stormwater pursuant to §4.110(24). See also "Contact stormwater" and "Stormwater."

(64) Oil and gas NORM waste--Any solid, liquid, or gaseous material or combination of materials (excluding source material, special nuclear material, and by-product material) that in its natural physical state spontaneously emits radiation, is discarded or unwanted, constitutes, is contained in, or has contaminated oil and gas waste, and prior to treatment or processing that reduces the radioactivity concentration, exceeds exemption criteria specified in 25 Texas Administrative Code §289.259(d) (relating to Licensing of Naturally Occurring Radioactive Material (NORM)).

(65) Oil and gas wastes--As defined in Texas Natural Resources Code §91.1011, the term:

(A) means waste that arises out of or incidental to the drilling for or producing of oil or gas, including waste arising out of or incidental to:

(i) activities associated with the drilling of injection water source wells which penetrate the base of useable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the Commission;

(iii) activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in Texas Natural Resources Code §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in Texas Natural Resources Code §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(B) includes salt water, brine, sludge, drilling mud, and other liquid, semiliquid, or solid waste material; but

(C) does not include waste arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, 42 U.S.C. 6901 et seq., as amended.

(66) Oil field fluids--Fluid used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and other chemicals used in association with oil and gas activities, but does not include produced oil, condensate, gas, or water that is not oil and gas waste. Oil field fluids no longer used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, and oil field fluids that have been abandoned, are considered an oil and gas waste.

(67) Operator--A person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the Commission's rules and regulations in any acts subject to the Commission's jurisdiction.

(68) Partially treated waste--Oil and gas waste that has been treated or processed with the intent of being recycled, but which has not been determined to meet the environmental and engineering standards for a recyclable product established by the Commission in this subchapter or in a permit issued pursuant to this subchapter.

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

(70) Pit--A container for which earthen materials provide structure, shape, and foundation support. A container that includes a concrete floor or sidewall is a pit. A tank, as defined in paragraph (89) of this section, is not a pit.

(71) Pollution--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water that renders the water 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.

(72) Primary containment--Measures put into place to confine, control, and secure a material to a defined space. See also "Container."

(73) Produced water--The water that was present in a subsurface formation and was brought to the surface during oil and gas exploration and production activities.

(74) Produced water recycling--The recycling of produced water and other aqueous fluid wastes produced from a wellbore during oil and gas exploration and production activities.

(75) Produced water recycling pit--An authorized pit used to manage produced water and other aqueous fluid wastes produced from a wellbore during oil and gas exploration and production activities.

(76) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, any portion of a park, city, town, village, or other similar area that can expect to be populated.

(77) Public water system--A source of potable water for the public's use that has at least 15 service connections or serves at least 25 individuals for at least 60 days out of the year. This includes people that live in houses served by a system, but can also include employees, customers, or students.

(78) Pressure maintenance plant or repressurizing plant--A plant for processing natural gas for reinjection for reservoir pressure maintenance or repressurizing in a natural gas recycling project. These terms do not include a compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system.

(79) Receiver--A person who manages oil and gas waste that is received from a generator, another receiver, or carrier. A receiver of another operator's oil and gas wastes may be a generator of its own oil and gas wastes.

(80) Recyclable product--A reusable material that has been created from the treatment and/or processing of oil and gas waste as authorized or permitted by the Commission and that meets the environmental and engineering standards established by the permit or authorization for the intended use, and is used as a legitimate commercial product. A recyclable product is not a waste but may become a waste if it is abandoned or disposed of rather than recycled as authorized by the permit or authorization.

(81) Recycle--To process and/or use or re-use oil and gas wastes as a product for which there is a legitimate commercial use. This term also includes the actual use or re-use of oil and gas wastes. For the purpose of this chapter, the term "recycle" does not include injection pursuant to a permit issued under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs).

(82) Reserve pit--A pit used in conjunction with drilling rig for collecting spent drilling fluids; cuttings, sands, and silts; and wash water used for cleaning drill pipe and other equipment at the well site. Reserve pits are sometimes referred to as slush pits or mud pits.

(83) Secondary containment--Measures put into place to contain spills and prevent them from contaminating the surrounding area, such as dikes, berms, or other barriers. See also "Container" and "Primary containment."

(84) Sensitive area--An area defined by the presence of factors, whether one or more, that make it vulnerable to pollution from oil

and gas surface waste management activities. Factors that are characteristic of sensitive areas include the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, streams, dry or flowing creeks, irrigation canals, water wells, stock tanks, and wetlands; proximity to natural wildlife refuges or parks; or proximity to commercial or residential areas.

(85) Solid oil and gas waste--Oil and gas waste that is determined not to contain "free liquids" as defined by EPA Method 9095B (Paint Filter Liquids Test), as described in "Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods" (EPA Publication Number SW-846).

(86) Storage or storing--The keeping, holding, accumulating, or aggregating of oil and gas waste for a temporary or indeterminate period.

(87) Stormwater--Water that falls onto and flows over the ground surface and does not infiltrate into the soil. See also "Contact stormwater" and "Non-contact stormwater."

(88) Surface and subsurface water--Groundwater, percolating, perched or otherwise, and lakes, bays, ponds, impounding reservoirs, springs, rivers, streams, creeks, estuaries, marshes, wetlands, inlets, canals, the Gulf of Mexico inside the territorial limits of the state, and all other bodies of surface water, natural or artificial, inland or coastal, fresh, saline, or salt, navigable or non-navigable, and including the beds and banks of all watercourses and bodies of surface water, that are wholly or partially inside or bordering the state or inside the jurisdiction of the state.

(89) Tank--A rigid, non-concrete, non-earthen container that provides its own structure and shape.

(90) TCEQ--The Texas Commission on Environmental Quality or its successor agencies.

(91) Technical Permitting Section or Technical Permitting--The Technical Permitting Section within the Oil and Gas Division of the Railroad Commission of Texas, located in Austin, Texas.

(92) Treated fluid--Fluid oil and gas waste that has been treated to remove impurities such that the fluid can be reused or recycled. Treated fluid that is abandoned or disposed of is classified as an oil and gas waste. Once treated fluid is reused or recycled, it is not classified as an oil and gas waste.

(93) Unified Soil Classification System--The standardized system devised by the United States Army Corps of Engineers for classifying soil types.

(94) Waste management unit--A container, structure, pad, cell, or area in or on which oil and gas wastes are managed.

(95) Water condensate pit--A pit used for storage or disposal of water condensed from natural gas.

(96) Wetland--An area including a swamp, marsh, bog, prairie pothole, or similar area having a predominance of hydric soils that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support and that under normal circumstances supports the growth and regeneration of hydrophytic vegetation. The term "hydric soil" means soil that, in its undrained condition, is saturated, flooded, or ponded long enough during a growing season to develop an anaerobic condition that supports the growth and regeneration of hydrophytic vegetation. The term "hydrophytic vegetation" means a plant growing in water or a substrate that is at least periodically deficient in oxygen during a growing season as a result of excessive water content. The term "wetland" does not include irrigated acreage used as farmland; a man-made wetland of less than one acre; or a man-made wetland for which construction or creation commenced on or after August 28, 1989, and which was not constructed with wetland creation as a stated objective, including but not limited to an impoundment made for the purpose of soil and water conservation which has been approved or requested by soil and water conservation districts (Texas Water Code §11.502.).

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 17, 2024.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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For further information, please call: (512) 475-1295

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DIVISION 3. OPERATIONS AUTHORIZED BY RULE

16 TAC §§4.111 - 4.115

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.112. Authorized Recycling.

(a) Produced water recycling is authorized if:

(1) produced water is recycled for use in drilling operations, completion operations, hydraulic fracturing operations, or as another type of oilfield fluid to be used in the wellbore of an oil, gas, geothermal, or service well;

(2) produced water recycling pits are operated in accordance with §4.113 and §4.115 of this title (relating to Authorized Pits, and Schedule B Authorized Pits); and

(3) recycling is limited to oil and gas waste; commingling of treated oil and gas waste with other treated fluid from sources outside of the Commission's jurisdiction may only be authorized at the Director's discretion.

(b) Treated fluid may be reused in any other manner without a permit from the Commission provided the reuse occurs pursuant to a permit issued by another state or federal agency.

(c) Fluid that meets the requirements of subsection (a) or (b) of this section is a recyclable product.

§4.113. Authorized Pits.

(a) An operator may, without a permit, maintain or use reserve pits, mud circulation pits, completion/workover pits, makeup water pits, fresh mining water pits, water condensate pits, and produced water recycling pits if the pit complies with this division.

(b) Unless otherwise approved by the District Director after a showing that the contents of the pit will be confined in the pit at all times, all authorized pits shall be constructed, used, operated, and maintained at all times outside of a 100-year flood plain as that term is defined in §4.110 of this title (relating to Definitions). The operator may request a hearing if the District Director denies approval of the request to construct an authorized pit within a 100-year flood plain.

(c) An authorized pit that was constructed pursuant to and compliant with §3.8 of this title (relating to Water Protection) as that rule existed prior to July 1, 2025, is authorized to continue to operate subject to the following:

(1) Authorized pits that cause pollution shall be brought into compliance with or closed according to this division.

(2) By July 1, 2026, basic sediment pits, flare pits, and other unpermitted pits not authorized by this section shall be:

(A) permitted according to this subchapter; or

(B) closed according to this division.

(3) By January 1, 2026, an operator of a non-commercial fluid recycling pit shall:

(A) register the pit as a produced water recycling pit according to subsection (e) of this section and file the required financial security according to §4.115 of this tile (relating to Schedule B Authorized Pits); or

(B) close the pit according to this division.

(4) At the time of closure, authorized pits shall be closed according to this division.

(d) In the event of an unauthorized release of oil and gas waste, treated fluid, or other substances from any pit authorized by this section, the operator shall take any measures necessary to stop or control the release and report the release to the District Office within 24 hours of discovery of the release.

(e) The operator shall register all authorized pits with the Commission.

(1) The Director shall establish a registration system for authorized pits by July 1, 2025.

(A) New authorized pits constructed after July 1, 2025 shall register by mailing or emailing to Technical Permitting the registration form established by the Commission.

(B) By July 1, 2027, the Director will establish an online system for operators to register and for the Commission to maintain a record of authorized pits.

(C) The operator of an authorized pit shall register the pit using the online registration system once it is established by the Director.

(2) New pits shall be registered prior to operation of the pit.

(3) Authorized pits existing on July 1, 2025, shall be registered or closed within one year.

(4) Authorized pit registration shall include:

(A) the type of pit;

(B) the location of the pit including the lease name and number, drilling permit number or other Commission-issued identifier, and the latitude and longitude coordinates using the 1983 North American Datum (NAD);

(C) the pit dimensions and capacity in barrels;

(D) the expected depth to groundwater from the bottom of the pit; and

(E) for produced water recycling pits, the financial security required by §4.115 of this title.

(5) An authorized pit may be designated as more than one type of pit provided it meets the requirements in this section for each type of pit. An authorized pit of one type may be redesignated as an authorized pit of another type (for example, a reserve pit may be redesignated as a completion pit) provided the pit was constructed to meet the design and construction requirements of the pit type to which it will be redesignated.

§4.114. Schedule A Authorized Pits.

Reserve pits, mud circulation pits, completion/workover pits, makeup water pits, fresh mining water pits, and water condensate pits are Schedule A authorized pits.

(1) Schedule A pit contents.

(A) Reserve pits and mud circulation pits. A person shall not deposit or cause to be deposited into a reserve pit or mud circulation pit any oil field fluids or oil and gas wastes other than the following:

(i) drilling fluids that are freshwater base, saltwater base, or oil base;

(ii) drill cuttings, sands, and silts separated from the circulating drilling fluids;

(iii) wash water used for cleaning drill pipe and other equipment at the well site;

(iv) drill stem test fluids; and

(v) blowout preventer test fluids.

(B) Completion/workover pits. A person shall not deposit or cause to be deposited into a completion/workover pit any oil field fluids or oil and gas wastes other than spent completion fluids, workover fluid, and the materials cleaned out of the wellbore of a well being completed, worked over, or plugged.

(C) Makeup water pits. A person shall not deposit or cause to be deposited into a makeup water pit any oil and gas wastes or any oil field fluids other than water used to make up drilling fluid or hydraulic fracturing fluid. Produced water shall not be placed in a makeup water pit.

(D) Fresh mining water pits. A person shall not deposit or cause to be deposited into a fresh mining water pit any oil and gas wastes or any oil field fluids other than water used for solution mining of brine.

(E) Water condensate pits. A person shall not deposit or cause to be deposited into a water condensate pit any oil field fluids or oil and gas wastes other than fresh water condensed from natural gas and collected at gas pipeline drips or gas compressor stations.

(2) Schedule A pit construction.

(A) All pits shall be designed, constructed, and maintained to prevent any migration of materials from the pit into adjacent subsurface soils, groundwater, or surface water at any time during the life of the pit.

(B) Any authorized pit that contains fluid with more than 3,000 mg/liter of total dissolved solids, or any authorized pit located in areas where groundwater is present within 50 feet of the bottom of the pit shall be lined.

(i) All liners shall have a hydraulic conductivity that is 1.0 x 10-7 cm/sec or less.

(ii) A liner may be constructed of either natural or synthetic materials.

(3) Schedule A pit closure. A person who maintains or uses a reserve pit, mud circulation pit, makeup water pit, fresh mining water pit, completion/workover pit, or water condensate pit shall ensure closure activities do not increase the potential for pollution.

(A) Schedule A pits shall be dewatered, backfilled, and compacted according to the following schedule.

(i) Reserve pits, mud circulation pits, and makeup water pits which contain fluids with a chloride concentration of 6,100 mg/liter or less shall be dewatered, backfilled, and compacted within one year of cessation of drilling operations.

(ii) Reserve pits, mud circulation pits, and makeup water pits which contain fluids with a chloride concentration in excess of 6,100 mg/liter shall be dewatered within 30 days and backfilled and compacted within one year of cessation of drilling operations.

(iii) All completion/workover pits used when completing a well shall be dewatered within 30 days of well completion and backfilled and compacted within 120 days of well completion. All completion/workover pits used when working over a well shall be dewatered within 30 days of completion of workover operations and backfilled and compacted within 120 days of completion of workover operations.

(iv) Fresh mining water pits and water condensate pits shall be dewatered, backfilled, and compacted within 120 days of final cessation of use of the pit.

(v) If a person constructs a sectioned reserve pit, each section of the pit shall be considered a separate pit for determining when a particular section shall be dewatered.

(B) A person who maintains or uses a reserve pit, mud circulation pit, makeup water pit, or completion/workover pit shall remain responsible for dewatering, backfilling, and compacting the pit within the time prescribed by subparagraph (A) of this paragraph, even if the time allowed for backfilling the pit extends beyond the expiration date or transfer date of the lease covering the land where the pit is located.

(C) The Director may require that a person who uses or maintains a reserve pit, mud circulation pit, makeup water pit, fresh mining water pit, completion/workover pit, or water condensate pit dewater and backfill the pit sooner than the time prescribed by subparagraph (A) of this paragraph if the Director determines that oil and gas wastes or oil field fluids are likely to escape from the pit or that the pit is being used for improper storage or disposal of oil and gas wastes or oil field fluids.

(D) Prior to backfilling any reserve pit, mud circulation pit, completion/workover pit, or water condensate pit authorized by this paragraph, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by §4.111 of this title (relating to Authorized Disposal Methods for Certain Wastes), dispose of all oil and gas wastes which are in the pit.

§4.115. Schedule B Authorized Pits.

(a) Schedule B authorized pits. A produced water recycling pit is a Schedule B authorized pit.

(b) A produced water recycling pit may be located on a tract of land that is not on an oil and gas lease operated by the operator of the produced water recycling pit.

(c) Financial security requirements.

(1) Pursuant to Natural Resources Code §91.109(a), the operator of a produced water recycling pit shall maintain a performance bond or other form of financial security conditioned that the operator will operate and close the produced water recycling pit in accordance with this subchapter.

(2) For each produced water recycling pit an operator shall file financial security in one of the following forms:

(A) a blanket performance bond; or

(B) a letter of credit or cash deposit in the same amount as required for a blanket performance bond.

(3) An operator required to file financial security under paragraph (1) of this subsection shall file one of the following types and amounts of financial security.

(A) A person operating five or less pits may file a performance bond, letter of credit, or cash deposit in an amount equal to $1.00 per barrel of total pit capacity.

(B) A person operating more than five pits may file a performance bond, letter of credit, or cash deposit in an amount equal to:

(i) the greater of $1.00 per barrel of water for ten percent of an operator's total produced water recycling pit capacity or $1,000,000; or

(ii) $200,000 per pit, capped at $5,000,000.

(4) The operator shall submit required financial security at the time the operator registers the produced water recycling pit.

(5) The operator shall submit bonds and letters of credit on forms prescribed by the Commission.

(d) Non-commercial fluid recycling pits authorized prior to July 1, 2025. Non-commercial fluid recycling pits that were authorized pursuant to and compliant with §3.8 of this title (relating to Water Protection) as that rule existed prior to July 1, 2025 are authorized as produced water recycling pits under this section, provided the operator registers the pit and files the required financial security by January 1, 2026.

(e) Produced water recycling pit contents. A person shall not deposit or cause to be deposited into a produced water recycling pit any oil field fluids or oil and gas wastes other than those fluids described in §4.110(75) of this title (relating to Definitions) and any fluids authorized by the Director pursuant to §4.112(a)(3) of this title (relating to Authorized Recycling).

(f) General location requirements for produced water recycling pits. No produced water recycling pit shall be located:

(1) on a barrier island or a beach;

(2) within 300 feet of surface water;

(3) within 500 feet of any public water system well or intake;

(4) within 300 feet of any domestic water well or irrigation water well, other than a well that supplies water for drilling or workover operations or any other process for which the pit is authorized;

(5) within a 100-year flood plain; or

(6) within 500 feet of a public area.

(g) General design and construction requirements for produced water recycling pits. All produced water recycling pits shall comply with the following requirements.

(1) The operator shall design and construct a produced water recycling pit to ensure the confinement of fluids to prevent releases.

(2) A produced water recycling pit shall be large enough to ensure adequate storage capacity of the volume of material to be managed and to maintain two feet of freeboard plus the capacity to contain the volume of precipitation from a 25-year, 24-hour rainfall event.

(3) A produced water recycling pit shall be designed and constructed to prevent non-contact stormwater runoff from entering the pit. A berm, ditch, proper sloping, or other diversion shall surround a produced water recycling pit to prevent run-on of any surface waters including precipitation.

(4) A produced water recycling pit shall have a properly constructed foundation and interior slopes consisting of a firm, unyielding base, smooth and free of rocks, debris, sharp edges, or irregularities to prevent the liner's rupture or tear. The operator shall construct a produced water recycling pit so that the slopes are no steeper than three horizontal feet to one vertical foot (3H:1V). The District Director may approve an alternative to the slope requirement if the operator demonstrates that it can construct and operate the produced water recycling pit in a safe manner to prevent pollution of surface and subsurface water and protect public health, public safety, and the environment.

(5) Produced water recycling pits shall be lined.

(A) The liner shall be constructed of materials that have sufficient chemical and physical properties, including thickness, to prevent failure during the expected life of the produced water recycling pit due to pressure gradients (including static head and external hydrogeologic forces), physical contact with material in the pit or other materials to which the liner may be expected to be exposed, climatic conditions, stress of installation, and use.

(B) All of the pit shall be lined, including the dike or berm, and the liner shall be properly anchored or keyed into the native substrate to prevent erosion or washout of the dike, berm, or liner.

(C) A liner may be constructed of either natural or synthetic materials.

(D) A liner constructed of natural materials shall meet the following requirements:

(i) A natural liner shall only be used for a produced water recycling pit with an active life of less than one year.

(ii) A natural liner shall be constructed of a minimum of two feet of compacted fat clay, placed in continuous six-inch lifts compacted to a 95% standard proctor as defined in ASTM D698 and having a hydraulic conductivity of 1.0 x 10 7 cm/sec or less. Where natural liner materials are used, the operator shall perform appropriate testing to ensure compliance with these requirements and shall maintain copies of the test results for the life of the pit.

(iii) A produced water recycling pit with a natural liner shall not be used for waste disposal pursuant to §4.111 of this title (relating to Authorized Disposal Methods for Certain Wastes) unless the pit also has a synthetic liner.

(E) A synthetic liner shall meet the following requirements:

(i) A synthetic liner shall be placed upon a firm, unyielding foundation or base capable of providing support to the liner, smooth and free of rocks, debris, sharp edges, or irregularities to prevent the liner's rupture or tear.

(ii) A synthetic liner shall be underlain by a geotextile where needed to reduce localized stress, strain, or protuberances that may otherwise compromise the liner's integrity.

(iii) A synthetic liner shall be made of an impermeable geomembrane capable of resisting pressure gradients above and below the liner to prevent failure of the liner.

(iv) A synthetic liner shall have a breaking strength of 40 pounds per inch using test method ASTM D882.

(v) A synthetic liner shall have a puncture resistance of at least 15 pounds force using test method ASTM D4833.

(vi) The length of synthetic liner seams shall be minimized, and the seams shall be oriented up and down, not across, a slope. The operator shall use factory welded seams where possible. Prior to field seaming, the operator shall overlap liners four to six inches. The operator shall minimize the number of field seams in corners and irregularly shaped areas. Qualified personnel shall field weld and test liner seams. A synthetic liner shall have a seam strength, if applicable, of at least 15 pounds per inch using test method ASTM D751 or ASTM D6392.

(h) General operating requirements for produced water recycling pits. All produced water recycling pits shall be operated in accordance with the following requirements.

(1) Freeboard of at least two feet plus capacity to contain the volume of precipitation from a 25-year, 24-hour rainfall event shall always be maintained in produced water recycling pits.

(2) Equipment, machinery, waste, or other materials that could reasonably be expected to puncture, tear, or otherwise compromise the integrity of the liner shall not be used or placed in lined pits.

(3) Operators shall establish an inspection program to ensure compliance with the applicable provisions of this section taking into consideration the nature of the pit and frequency of use.

(4) If the operator does not propose to empty the produced water recycling pit and inspect the pit liner on at least an annual basis, the operator shall install a double liner and leak detection system. A leak detection system shall be installed between a primary and secondary liner. The leak detection system shall be monitored monthly to determine if the primary liner has failed. The primary liner has failed if the volume of water passing through the primary liner exceeds the action leakage rate, as calculated using accepted procedures, or 1,000 gallons per acre per day, whichever is larger.

(5) The operator of a produced water recycling pit shall keep records to demonstrate compliance with the pit liner integrity requirements and shall make the records available to the Commission upon request.

(6) Free oil shall not be allowed to accumulate on or in a produced water recycling pit.

(i) General closure requirements for produced water recycling pits. All produced water recycling pits shall comply with the following closure requirements.

(1) Prior to closure of the pit, the operator shall dewater the pit.

(2) Prior to closure of the pit, all waste shall be removed from the pit unless the requirements of subsection (k) of this section are met.

(j) Closure requirements for produced water recycling pits if all waste is removed for disposal.

(1) The contents of the pit, including synthetic liners, if applicable, shall be removed for disposal at an authorized or permitted waste facility.

(2) The operator shall verify whether oil and gas waste has migrated beyond the pit floor and sidewalls.

(3) The operator shall collect one five-point composite soil sample for each acre of pit surface area. The five-point composite sample shall be collected from the native soil on the pit floor. A fraction of an acre of pit surface area will require a composite sample.

(A) The samples shall be analyzed for the constituents and using the methods identified in the figure in this subsection to determine whether the constituent concentrations exceed the limit in the figure or background concentrations.

(B) If the operator intends to use background soil concentrations as a closure standard, then constituent concentrations in background soil shall be determined before or during pit construction. To establish background concentrations, the operator shall:

(i) sample soil in the pit floor locations before or during pit construction;

(ii) collect one five-point composite soil sample for each acre of pit surface area. The five-point composite sample shall be collected from the native soil on the pit floor. A fraction of an acre of pit surface area will require a composite sample; and

(iii) analyze the soil samples for the constituents listed in the figure in this subsection.

(C) If the concentration of the constituents exceeds the limits in the figure in this subsection or the concentrations determined from background sampling and analysis, the operator shall notify the District Director within 24 hours of discovery of the constituent exceedance.

(i) The District Director may refer the matter to the Site Remediation Unit in Austin.

(ii) The operator shall follow instructions provided by the District Director or Site Remediation regarding further investigation, remediation, monitoring, closure, and reporting.

(D) If the concentration of the constituents does not exceed the limits in the figure in this subsection or background concentrations, the operator shall proceed with closure.

(i) The operator shall backfill the pit with non-waste containing, uncontaminated, earthen material.

(ii) The backfill shall be compacted in a manner that minimizes future consolidation, desiccation, and subsidence.

(iii) The operator shall mound or slope the former pit site to encourage runoff and discourage ponding.

(iv) The operator shall, where necessary to ensure ground stability and prevent significant erosion, vegetate the former pit site in a manner consistent with natural vegetation in undisturbed soil in the vicinity of the pit.

(E) The operator shall notify the District Director a minimum of seven days prior to closure of the produced water recycling pit and shall maintain documentation for a period of three years to demonstrate that the requirements of this section have been met.
Figure: 16 TAC §4.115(j)(3)(E)

(k) Closure requirements for produced water recycling pits if waste will be buried in place pursuant to §4.111 of this title.

(1) The operator shall ensure that any oil and gas waste, including synthetic liners, that will be disposed of in the pit as authorized by §4.111 of this title is buried in a manner such that the waste will remain below the natural ground surface and be confined to the original dimensions of the pit.

(2) The operator shall determine the suitability of the waste material or mixture for disposal in the pit.

(A) The operator shall collect one five-point composite waste material or mixture sample for each acre of pit surface area. A fraction of an acre of pit surface area will require a composite sample.

(B) The samples shall be analyzed for the constituents and using the methods identified in the figure in this subsection to determine whether the constituent concentrations are below the limit in the figure or background concentrations.

(C) If the operator intends to use background soil concentrations as a closure standard, then constituent concentrations in background soil shall be determined before or during pit construction. To establish background concentrations, the operator shall:

(i) sample soil in the pit floor locations before or during pit construction;

(ii) collect one five-point composite soil sample for each acre of pit surface area. The five-point composite sample shall be collected from the native soil on the pit floor. A fraction of an acre of pit surface area will require a composite sample; and

(iii) analyze the soil samples for the constituents listed in the figure in this subsection.

(3) Waste material that meets the constituent limits in the figure in subsection (j) of this section or background concentrations may be buried in the pit without additional disposal considerations.

(4) Untreated waste material that does not meet the constituent limits in the figure in subsection (j) of this section may be buried by containment in a pit if:

(A) the pit has a double liner with a leak detection system or has a single liner for which the operator demonstrates the liner is intact and maintains the liner intact;

(B) the waste material is covered with a geonet to support the overburden fill material; and

(C) the pit is backfilled, sufficiently compacted, and contoured to prevent water infiltration into the waste zone.

(5) Treated waste material that meets the constituent limits in the figure in this subsection based on the distance from the bottom of the pit to the shallowest groundwater may be buried in the pit. Liners in the pit may be removed from the pit or disposed of in the pit upon closure.

(6) The operator shall proceed with closure as follows:

(A) The operator shall backfill the pit with non-waste containing, uncontaminated, earthen material.

(B) The backfill shall be compacted in a manner that minimizes future consolidation, desiccation, and subsidence.

(C) The operator shall mound or slope the burial pit site to encourage runoff and discourage ponding.

(D) The operator shall, where necessary to ensure ground stability and prevent significant erosion, vegetate the former pit site in a manner consistent with natural vegetation in undisturbed soil in the vicinity of the pit.

(7) The operator shall notify the District Director a minimum of seven days prior to closure of the produced water recycling pit and shall maintain documentation for a period of three years to demonstrate that the requirements of this section have been met.

(8) The Commission may require the operator to close a produced water recycling pit in a manner other than the manner described in this section if it determines that oil and gas wastes or oil field fluids are likely to escape from the pit, that oil and gas wastes or oil field fluids may cause or are causing pollution, and/or that the pit is being used in a manner inconsistent with Commission rules.
Figure: 16 TAC §4.115(k)(8)

(9) If groundwater monitoring wells are required pursuant to subsection (l) of this section, then groundwater monitoring shall continue on the same terms for at least five years after the produced water recycling pit has been closed.

(l) Groundwater monitoring requirements for Schedule B authorized pits.

(1) For all Schedule B authorized pits, the operator shall evaluate whether groundwater is likely to be present within 100 feet of the ground surface. The operator shall review readily available public information to evaluate whether groundwater is likely to be present within 100 feet of the ground surface. The presence of a water well within a one-mile radius of the pit that produced or produces water from a depth of 100 feet or less indicates groundwater is likely to be present within 100 feet of the ground surface. If the operator cannot determine whether groundwater is likely to be present within 100 feet of the ground surface based on a review of readily available public information, the operator shall obtain location-specific subsurface information to establish the presence or absence of groundwater within 100 feet of the ground surface.

(2) Operators of Schedule B authorized pits located in areas where groundwater is not likely to be present within 100 feet of the ground surface are not required to perform groundwater monitoring.

(3) Operators of Schedule B authorized pits located in areas where groundwater is likely to be present within 100 feet of the ground surface are required to perform groundwater monitoring in accordance with paragraph (4) of this subsection unless:

(A) the pit has a double synthetic liner with an operational leak detection system; or

(B) the pit has a liner and an active life of less than one year.

(4) When groundwater monitoring is required under this subsection, the operator shall install at least three groundwater monitoring wells, at least two of which are installed in a hydrologic downgradient location relative to the pit and at least one of which is installed in an upgradient location relative to the pit.

(5) The following is required for each soil boring or groundwater monitoring well drilled.

(A) The drilling method shall allow for periodic or continuous collection of soil samples for field screening and soil characterization in order to adequately characterize site stratigraphy and groundwater bearing zones.

(B) The groundwater monitoring wells shall be completed by a certified water well driller in accordance with 16 TAC Part 4, Chapter 76 (Water Well Drillers and Water Well Pump Installers).

(C) The groundwater monitoring wells shall be completed to penetrate the shallowest groundwater zone, and the completion shall isolate that zone from any deeper groundwater zone.

(D) The screened interval of the groundwater monitoring wells shall be designed to intercept at least five feet of groundwater.

(E) The groundwater monitoring well screen shall extend above the static water level.

(F) The sand pack size shall be compatible with the well screen slot size, as well as the local lithology.

(G) The groundwater monitoring well heads shall be protected from damage by vehicles and heavy equipment.

(H) The groundwater monitoring wells shall be maintained in good condition with a lockable watertight expansion cap.

(I) The groundwater monitoring wells shall be able to provide a sample that is representative of the groundwater underlying the site for the duration of pit operations.

(J) The operator shall retain the following information for three years after the monitoring wells are plugged:

(i) a soil boring lithological log for the well, with the soils described using the Unified Soil Classification System (USCS) (equivalent to ASTM D 2487 and ASTM D 2488); the method of drilling; well specifications; slotted screen type and slot size; riser and

screen length; bentonite and cement intervals; total depth; and the depth of the first encountered groundwater or saturated soils;

(ii) a well installation diagram, detailing construction specifications for each well;

(iii) a survey elevation for each well head reference point to the top of the casing relative to a real or arbitrary on-site benchmark or relative to mean sea level;

(iv) a table with recorded depth to water, depth to top of casing, and adjusted depth to water data;

(v) an updated Site Plan and a potentiometric surface map showing static water levels, the calculated gradient, and the estimated direction of groundwater flow; and

(vi) the laboratory analytical reports and the corresponding chain of custody from each groundwater sampling event.

(6) The operator shall sample the wells after installation of the wells is complete and shall then sample the wells on a quarterly schedule.

(7) The wells shall be monitored and/or sampled for the following parameters: the static water level, pH, and concentrations of benzene, total petroleum hydrocarbons, total dissolved solids, soluble cations (calcium, magnesium, potassium, and sodium), and soluble anions (bromides, carbonates, chlorides, nitrates, and sulfates).

(8) If any of the parameters identified in paragraph (7) of this subsection indicate pollution:

(A) the operator shall notify the District Director by phone or email within 24 hours of receiving the analytical results; and

(B) the District Director will determine whether additional remediation, monitoring, or other actions are required.

(m) Transfers. To transfer a Schedule B authorized pit, the new operator of the pit shall:

(1) file a registration with the Commission 30 days in advance of the effective date of the transfer; and

(2) submit the financial security required by this section by the effective date of the transfer.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Haley Cochran
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DIVISION 4. REQUIREMENTS FOR ALL PERMITTED WASTE MANAGEMENT OPERATIONS

16 TAC §§4.120 - 4.132, 4.134, 4.135

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.120. General Requirements for All Permitted Operations.

(a) A waste management activity or facility that is not authorized under Division 3 of this subchapter shall require a permit.

(b) If an activity or facility requires a permit, then all waste management units associated with the activity or facility, including pits authorized by sections §4.113, §4.114, or §4.115 of this title (relating to Authorized Pits, Schedule A Authorized Pits, and Schedule B Authorized Pits) must be included in the permit. Authorized activities require a permit if associated with a permitted activity or facility.

(c) The Commission may issue a permit to manage oil and gas wastes only if the Commission determines that the activity will not result in the endangerment of human health or the environment, the waste of oil, gas, or geothermal resources, or pollution of surface or subsurface water.

(d) This division establishes the permit requirements applicable to all permitted waste management operations. Any person engaged in waste management authorized by permit shall comply with the requirements in this division.

(e) A person applying for or acting under a Commission permit to manage oil and gas waste may be required to maintain a performance bond or other form of financial security conditioned that the permittee will operate and close the management facility in accordance with state law, Commission rules, and the permit to operate the facility.

(f) In addition to the requirements in this division, any person engaged in the following waste management operations shall comply with the requirements of the following, as applicable.

(1) Requirements applicable to commercial facilities are found in Division 5 of this subchapter (relating to Additional Requirements for Commercial Facilities).

(2) Requirements applicable to permitted pits are found in Division 6 of this subchapter (relating to Additional Requirements for Permitted Pits).

(3) Requirements applicable to landfarming and landtreating are found in Division 7 of this subchapter (relating to Additional Requirements for Landfarming and Landtreating).

(4) Requirements for reclamation operations are found in Division 8 of this subchapter (relating to Additional Requirements for Reclamation Plants).

(5) Miscellaneous permit requirements applicable to emergency permits, minor permits, and all other activities not otherwise authorized or addressed in this subchapter are found in Division 9 of this subchapter (relating to Miscellaneous Permits).

(6) Requirements applicable to oil and gas waste characterization, documentation, manifests, and transportation are found in Division 10 of this subchapter (relating to Requirements for Oil and Gas Waste Transportation).

(g) With regard to permits issued pursuant to Divisions 4 through 9 of this subchapter, the Director may impose additional permit conditions necessary to protect human health and the environment, to prevent the waste of oil, gas, or geothermal resources, or to prevent pollution of surface or subsurface water.

§4.125. Notice and Opportunity to Protest.

(a) Purpose. Applicants are encouraged to engage with their communities early in the waste facility planning process to inform the community of the plan to construct a facility and allow those who may be affected by the proposed activities to express their concerns. The purpose of the notice required by this section is to inform notice recipients:

(1) that an applicant has filed a permit application with the Commission, seeking authorization to conduct an activity or operate a facility; and

(2) of the requirements for filing a protest if an affected person seeks to protest the permit application.

(b) Timing of notice. The applicant shall provide notice after staff determines that an application is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively). The date notice is completed begins a 30-day period in which an affected person may file a protest of the application with the Commission.

(c) Notice recipients. The applicant shall provide notice to:

(1) the surface owners of the tract on which the facility will be located;

(2) the surface owners of tracts adjacent to the tract on which the facility will be located;

(3) the surface owners of tracts located within 500 feet of the facility's fence line or boundary, even if the surface owner's tract is not adjacent to the tract on which the facility is located;

(4) the city clerk or other appropriate city official if any part of the tract on which the facility will be located lies within the municipal boundaries of the city;

(5) the Commission's District Office; and

(6) any other person or class of persons that the Director determines should receive notice of an application.

(d) Method and contents of notice. Unless otherwise specified in this subchapter, the applicant shall provide direct notice to the persons specified in subsection (c) of this section as follows.

(1) The applicant shall provide notice by registered or certified mail. Notice is completed upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

(2) The notice of the permit application shall consist of a complete copy of the application and any attachments. The copy shall be of the application and attachments after staff determines the application is complete pursuant to §1.201(b) of this title but before the final review is completed.

(3) The notice shall include a letter that contains:

(A) the name of the applicant;

(B) the date of the notice;

(C) the name of the surface owners of the tract on which the proposed facility will be located;

(D) the location of the tract on which the proposed facility will be located including a legal description of the tract, latitude/longitude coordinates of the proposed facility, county, original survey, abstract number, and the direction and distance from the nearest municipality or community;

(E) the types of fluid or waste to be managed at the facility;

(F) a statement that an affected person may protest the application by filing a written protest with the Commission within 30 calendar days of the date notice is completed;

(G) a statement that a protest shall include the protestant's name, mailing address, telephone number, and email address;

(H) the address to which protests may be mailed or the location and instructions for electronic submittal of a protest if the Commission implements an electronic means for filing protests;

(I) the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(J) the signature of the operator, or representative of the operator, and the date the letter was signed.

(4) If the Director determines that the applicant, after diligent efforts, has been unable to ascertain the name and address of one or more persons required by this section to be notified, then the Director may authorize the applicant to notify such persons by publishing notice of the application in accordance with the procedure and contents required by §4.141 of this title (relating to Additional Notice Requirements for Commercial Facilities). The Director will consider the applicant to have made diligent efforts to ascertain the names and addresses of surface owners required to be notified if the applicant has examined

the current county tax rolls and investigated other reliable and readily available sources of information.

(e) Proof of notice.

(1) After the applicant provides the notice required by this section, the applicant shall submit to the Commission proof of delivery of notice which shall consist of:

(A) a copy of the signed and dated letters required by subsection (d)(3) of this section;

(B) the registered or certified mail receipts; and

(C) a map showing the property boundaries, surface owner names, and parcel numbers of all notified parties.

(2) If the Director authorizes notice by publication in accordance with subsection (d)(4) of this section, the applicant shall provide the following as proof of notice:

(A) an affidavit from the newspaper publisher that states the dates on which the notice was published and the county or counties in which the newspaper is of general circulation; and

(B) the tear sheets for each published notice.

(f) Protest process. Any statement of protest to an application must be filed with the Commission within 30 calendar days from the date notice is completed or from the last date of publication if notice by publication is authorized by the Director.

(1) The Technical Permitting Section shall notify the applicant if the Commission receives an affected person's timely protest. A timely protest is a written protest date-stamped as received by the Commission within 30 calendar days of the date notice is completed or within 30 calendar days of the last date of publication, whichever is later.

(2) The applicant shall have 30 days from the date of the Technical Permitting Section's notice of receipt of protest to respond, in writing, by either requesting a hearing or withdrawing the application. If the applicant fails to timely file a written response, the Technical Permitting Section shall consider the application to have been withdrawn.

(3) The Technical Permitting Section shall refer all protested applications to the Hearings Division if a timely protest is received and the applicant requests a hearing.

(4) The Commission shall provide notice of any hearing convened under this subsection to all affected persons and persons who have requested notice of the hearing.

(5) If the Director has reason to believe that a person entitled to notice of an application has not received notice as required by this section, then the Technical Permitting Section shall not take action on the application until notice is provided to such person.

(6) The Commission may issue a permit if no timely protests from affected persons are received.

§4.128. Design and Construction.

(a) Application. The following information shall be submitted with each permit application:

(1) a facility diagram clearly showing the items listed in subparagraphs (A)-(G) of this paragraph and any other pertinent information regarding the facility and associated activities. Diagrams shall be on a scale that shows the entire facility and activities within the Commission's jurisdiction on a single page. The diagram shall show the following:

(A) a clear outline of the proposed facility, areas where oil and gas waste will be managed, and property boundaries;

(B) all wells, pits, areas where oil and gas waste will be managed, and any other activity under the jurisdiction of the Commission that may occur at the proposed facility;

(C) the location of all tanks and equipment;

(D) all berms, dikes, or secondary containment;

(E) all fences, roads, and paved areas;

(F) the shortest distance between the facility and waste management unit boundary to the nearest property line or public road; and

(G) the location of any pipelines within the facility boundaries;

(2) a description of the type and thickness of liners (e.g., fiberglass, steel, concrete), if any, for all tanks, silos, pits, and storage areas or cells;

(3) for storage areas where tanks and/or liners are not used, credible engineering and/or geologic information demonstrating that tanks or liners are not necessary for the protection of surface and subsurface water;

(4) a map view and two perpendicular cross-sectional views of pits and/or storage areas or cells to be constructed, showing the bottom, sides, and dikes and the dimensions of each; and

(5) a plan to control and manage all stormwater runoff and to retain wastes during wet weather, including the location and dimensions of dikes and/or storage basins that would collect stormwater during a 25-year, 24-hour rainfall event, and all calculations made to determine the required capacity and design.

(b) Design and construction requirements. All permittees shall comply with the following requirements.

(1) The permittee shall post signs at each entrance to the facility. The sign shall be readily visible and show the operator's name, facility name, and permit number in letters and numerals at least three inches in height.

(2) Dikes or containment structures shall be constructed around all areas managing oil and gas wastes. All earthen dikes surrounding pits and constructed as perimeter berms shall be compacted or constructed of material that meets 95% Standard Proctor (ASTM D698) or 90-92% Modified Proctor (ASTM D1557) density and meets a permeability of 1 x 10-7 cm/sec or less when compacted. During construction, successive lifts shall not exceed nine inches in thickness, and the surface between lifts shall be scarified to achieve a good seal. These structures shall be used to divert non-contact stormwater around the waste management unit and contain and isolate contact stormwater within the bermed area.

(3) Secondary containment shall be provided for all above-ground storage tanks. Secondary containment for a minimum of 120% total storage capacity is recommended. Secondary containment that will contain the largest tank's maximum capacity plus two feet of freeboard and capacity to contain the volume of precipitation from a 25-year, 24-hour rainfall event is acceptable.

(4) Contact stormwater shall be collected within 24 hours of accessibility and disposed of in an authorized manner.

(5) The facility shall maintain security to prevent unauthorized access. Fencing shall be required unless terrain or vegetation prevents vehicle or livestock access except through entrances with lockable gates. Access shall be secured by

(A) a 24-hour attendant; or

(B) if not attended, a six-foot-high security fence and locked gate to prevent vehicle or livestock access.

(6) All liner systems shall be installed and maintained in a manner that will prevent pollution and/or the escape of the contents of the pit.

§4.130. Reporting.

(a) The permittee shall maintain for a period of at least three years records of each Waste Profile Form and Waste Manifest described in §4.190 and §4.191 of this title (relating to Oil and Gas Waste Characterization and Documentation, and Oil and Gas Waste Manifests, respectively) that the permittee generated or received.

(b) The permittee shall make all records required by this section available for review and/or copying upon request.

(c) If a permit requires submittal of monthly, quarterly, semiannual, or annual reports, the report shall be submitted on a form prescribed by the Commission. If a Commission prescribed report form does not exist, the report shall contain a signature, printed name, contact telephone number or email address, the date of signing, and the following certification: "I certify that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that the data and facts stated herein are true, correct, and complete to the best of my knowledge."

(d) If a permit requires submittal of monthly, quarterly, semiannual, or annual reports, the report shall be submitted in accordance with the following requirements.

(1) If a permit requires quarterly reports, the quarterly reporting periods shall be January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31 of each year.

(2) If a permit requires quarterly, semi-annual, or annual reports, reports shall be made on a Commission-designated form or electronic filing system and submitted to the Technical Permitting Section and the Commission District Office no later than the 30th day of the month following each reporting period.

(3) If a permit requires monthly reports, the report shall be made on a Commission-designated form or electronic filing system and submitted to Technical Permitting Section and the District Office no later than the 15th day of the month following each reporting period.

(4) Reports may be filed with the Commission in paper form until one year after the date the Commission has the technological capability to receive electronic filings, at which time reports shall be filed electronically in a digital format acceptable to the Commission.

§4.131. Monitoring.

(a) Application. The following information shall be submitted with each permit application:

(1) a plan and schedule for conducting periodic inspections, including plans to inspect pits, equipment, processing, and storage areas; and

(2) a potentiometric contour map showing static water levels and the estimated direction of groundwater flow and the calculated gradient.

(b) Groundwater monitoring requirements.

(1) If shallow groundwater is present within 100 feet below ground surface, groundwater monitoring wells may be required for some facilities, including but not limited to: brine pits, disposal pits, reclamation plants, commercial waste separation facilities, commercial recycling facilities, and commercial landfarming or landtreating facilities. Factors that the Commission will consider in assessing whether groundwater monitoring is required include:

(A) the volume and characteristics of the oil and gas waste to be managed at the facility;

(B) depth to and quality of groundwater within 100 feet below ground surface; and

(C) presence or absence of natural clay layers in subsurface soils.

(2) If the Director requires the operator to install groundwater monitoring wells, the operator shall comply with the following.

(A) The operator shall submit a plan for the installation, sampling, and analysis of monitoring wells at the facility. The plan shall include information on the monitor well drilling method. A mud rotary drilling method shall not be used unless the depth to water has been established.

(B) The monitor wells shall be able to provide representative samples of groundwater underlying the site for the duration of facility operations. If a monitor well is not capable of providing a representative sample, the operator shall notify the Technical Permitting Section.

(C) If groundwater is not observed during drilling of the monitor wells, the soil boring shall be advanced to 100 feet. Borings shall be left open for a minimum of 24 hours to determine if groundwater is present.

(D) If shallow groundwater is present within 100 feet below ground surface at the site, a minimum of three groundwater monitoring wells shall be installed. Wells shall be spaced around the facility or pit, close to the facility operational area, with at least two wells on the estimated down-gradient side of the operational area. Additional wells may be required for larger facilities.

(E) The monitor wells shall be completed by a certified water well driller in accordance with 16 Texas Administrative Code, Part 4, Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers).

(F) The monitor wells shall be completed to penetrate the shallowest groundwater zone, and the completion shall isolate that zone from any deeper groundwater zone.

(G) The screened interval of the groundwater monitoring wells shall be designed to intercept at least five feet of groundwater.

(H) The groundwater monitoring well screen shall extend above the static water level.

(I) The sand pack size shall be compatible with the well screen slot size, as well as the local lithology.

(J) The groundwater monitoring well heads shall be protected from damage by vehicles and heavy equipment.

(K) The groundwater monitoring wells shall be maintained in good condition with a lockable watertight expansion cap.

(L) After installation of the wells is complete, the applicant shall submit the following information:

(i) a soil boring lithologic log for each well, with the soils described using the Unified Soil Classification System (equivalent

to ASTM D 2487 and 2488). The log shall also include the method of drilling, well specifications, slot size, riser and screen length, bentonite and cement intervals, total depth, and the top of the first encountered water or saturated soils; and

(ii) a survey elevation for each well head reference point (top of casing) relative to a real or arbitrary on-site benchmark and relative to mean sea level. Surveys shall be conducted by a licensed land surveyor.

(3) The applicant shall submit any other information necessary to address each of the operating requirements detailed in paragraph (4) of this subsection.

(4) If the Director requires the permittee to install groundwater monitoring wells, the permittee shall comply with the following requirements.

(A) The facility shall not manage oil and gas wastes at the facility until the groundwater monitoring wells are installed, the permittee submits the initial sample results to Technical Permitting Section, and Technical Permitting Section informs the permittee, in writing, that it may commence active operations.

(B) The permittee shall sample the wells after installation of the wells is complete and shall thereafter sample the wells in accordance with the schedule approved by the Technical Permitting Section, or as otherwise required by the Director.

(C) The following measurements and analyses shall be reported to Technical Permitting Section after any sampling event no later than 15 days after the permittee receives the laboratory analysis results: the static water level, pH, and concentrations of benzene, toluene, ethylbenzene, and xylenes (BTEX), total petroleum hydrocarbons, total dissolved solids, soluble cations (calcium, magnesium, potassium, and sodium), and soluble anions (bromides, carbonates, chlorides, nitrates, and sulfates).

(D) If any of the parameters identified in subparagraph (C) of this paragraph indicate pollution, or the potential failure of the liner system, the Commission may require additional monitoring events and/or may require analysis of additional parameters.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Railroad Commission of Texas
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For further information, please call: (512) 475-1295

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DIVISION 5. ADDITIONAL REQUIREMENTS FOR COMMERCIAL FACILITIES

16 TAC §§4.140 - 4.143

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.140. Additional Requirements for Commercial Facilities.

(a) In addition to the requirements of this division, all applicants for commercial facilities and permittees of commercial facility permits shall comply with Division 4 of this subchapter (relating to Requirements for All Permitted Waste Management Operations) and any other sections of this subchapter applicable to the applicant's or permittee's management of oil and gas wastes.

(b) A facility authorized or permitted as a non-commercial facility prior to July 1, 2025 but that meets the definition of a commercial facility in §4.110 of this title (relating to Definitions) as of July 1, 2025 shall comply with the requirements of this division or request an exception on or before July 1, 2026.

(c) A facility that meets the definition of a commercial facility in §4.110 of this title is considered a commercial facility under §3.78 of this title (relating to Fees and Financial Security Requirements), and therefore, an applicant for a commercial facility permit shall submit the financial security required by Texas Natural Resources Code §91.109 and §3.78 of this title for each permit renewal, amendment, and/or transfer.

(d) A commercial facility shall not manage oil and gas waste or otherwise begin active operation until the required financial security is approved and accepted by the Commission.

(e) Pursuant to §3.78 of this title, the amount of the financial security shall be the maximum dollar amount necessary to close the facility.

(f) The full financial security shall be maintained:

(1) until all post-closure activities are completed and approved by the Technical Permitting Section; and

(2) while the facility has been referred to and remedial actions are being overseen by the Site Remediation Unit in the Oil and Gas Division.

(g) To determine the maximum dollar amount necessary to close the facility, a professional engineer licensed in Texas shall prepare or supervise the preparation of a closure-cost estimate (CCE).

(1) In addition to the assumptions and calculations specified in §3.78 of this title, the professional engineer shall make the following assumptions when determining the dollar amount necessary to close the facility.

(A) The facility is in compliance with permit conditions.

(B) The facility will be closed according to the permit or approved closure plan, including the sampling and analysis of soils to confirm compliance.

(C) None of the operator's other equipment or facilities (e.g., disposal wells, pits, trucks, bulldozers, and employees) are available at the time of closure.

(D) The facility is at maximum capacity. All tanks and pits are full of waste. Disposal pits are fully constructed.

(E) Storage tanks and pits contain basic sediment and water in normal operating proportions, with a minimum volume of at least 10% basic sediment.

(2) The CCE shall not include a salvage or no cost value for any material or equipment at the facility.

(3) The CCE shall include costs for sampling and analysis of soil for the areas around each waste management unit, including tank batteries, pads, and former pits.

(4) The CCE shall show unit costs for all material, equipment, services, and labor needed to close the facility. Units and fees used shall be appropriate for the type of waste material to be disposed of. For example, disposal units for saltwater shall be reported in oil barrels rather than gallons. Solids held within permitted containments shall be reported in cubic yards. The CCE shall be specific and shall state the source or basis for the specific unit cost, including the following:

(A) the permitted waste hauler to be used and the hauler's mileage rate;

(B) the distance that waste will be transported for disposal;

(C) the name of each facility where waste will be taken and the disposal costs for that facility;

(D) the source of any material being brought to the facility, such as clean fill material;

(E) calculations for earth-moving equipment time and cost needed to move the fill dirt if fill dirt will be taken from the facility;

(F) the total labor costs, including the titles and billing rates for personnel; and

(G) the quantity of each unit cost item and how the total quantity was determined (for example, cubic yards of material divided by size of load equals total number of loads).

(5) The CCE shall include maps and illustrations such as facility plans and photographs that show the current condition of the facility, and/or the condition of the facility upon reaching maximum permit conditions.

(6) For facilities with groundwater monitoring wells, the CCE shall include costs to plug and abandon all monitoring wells.

(7) For facilities that will require post-closure monitoring, the CCE shall include costs for a minimum of five years of well maintenance and monitoring. The length of monitoring shall be determined by the Director.

(8) The CCE shall show all calculations used to arrive at total maximum closure costs.

(9) For all estimates submitted for existing facilities, a NORM screening survey of the facility shall be submitted. NORM screening surveys shall be performed using a properly calibrated scintillation meter with a sodium iodide detector (or equivalent), with the results reported in microroentgens per hour. Manufacturer's specifications and relevant calibration records shall be submitted to Technical Permitting Section in Austin for all devices used for NORM detection. All equipment, including piping, pumps, and vessels shall be surveyed. Readings shall be taken around the circumference of the pits and to the extent possible, over the pits. The ground surrounding the equipment and pits shall be surveyed in a systematic grid pattern. At a minimum, the following information shall be reported:

(A) the date of the survey;

(B) the instrument used and the last calibration date;

(C) a background reading;

(D) a facility diagram showing where all readings, including the background, were taken; and

(E) the readings (in microroentgens per hour).

(10) If fill dirt will be excavated from the property to achieve closure, a restrictive covenant shall be submitted with the CCE. If the restrictive covenant requirements are not provided, the CCE shall assume that fill dirt is purchased from a commercial supplier. For a restrictive covenant, the following requirements shall be met whether the operator owns or leases the property:

(A) The operator shall provide a letter from the property owner specifically stating that the owner agrees that the material, which is described with specificity as to location, type and amount consistent with what is in the closure plan, will be available for closure whether the operator or the state performs closure, and agreeing to a restrictive covenant that reserves use of the material for closure.

(B) The operator shall submit an unsigned draft restrictive covenant on the form provided by the Commission. Once the Commission approves the closure cost and closure plan, the operator will be notified to submit a signed original of the restrictive covenant. The Commission will sign its portion of the restrictive covenant and return it to the operator for filing in the real property records of the county where the property is located. Once filed in the real property records, the operator shall provide the Commission with a certified copy.

(C) If the facility operator leases the property, the operator shall provide to the Commission a copy of an amendment or addendum to the lease between the operator and the surface owner with a clause that specifically reserves use of material and states that the reservation shall inure to the Commission (as third-party beneficiary of this provision) if the Commission must initiate actions to close the facility.

(D) The operator shall submit supporting documentation showing that the dimensions of the restrictive covenant area can realistically store a stockpile in the amount needed. If soil will be excavated from the restrictive covenant area rather than stockpiled, the depth of the excavation is limited to what can be graded to prevent stormwater from ponding in the excavated area.

(11) After the CCE has been calculated, an additional 10% of that amount shall be added to the total amount of the CCE to cover contingencies.

(h) A permit application for a commercial facility shall include a detailed plan for closure of the facility when operations terminate and include the required elements of §4.132 of this title (relating to Closure). The closure plan shall address how the applicant intends to:

(1) remove waste, partially treated waste, and/or recyclable product from the facility;

(2) close all pits, treatment equipment, and associated piping and other storage or waste processing equipment;

(3) remove dikes and equipment;

(4) contour and reseed disturbed areas;

(5) sample and analyze soil and groundwater throughout the facility; and

(6) plug groundwater monitoring wells.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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DIVISION 6. ADDITIONAL REQUIREMENTS FOR PERMITTED PITS

16 TAC §§4.150 - 4.154

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.150. Additional Requirements Applicable to Permitted Pits.

(a) In addition to the requirements of this division, all permitted pits are required to comply with Division 4 of this subchapter (relating to Requirements for All Permitted Waste Management Operations). Commercial pits are also required to comply with Division 5 of this subchapter (relating to Additional Requirements for Commercial Facilities).

(b) If at any time a pit no longer meets the requirements for authorized pits under §4.113 of this title (relating to Authorized Pits), the operator of the pit shall apply for a pit permit pursuant to the requirements of this division.

(c) No person may use a pit without the express permission of the permittee. A person who uses a pit without the express permission of the permittee may be subject to legal enforcement action regardless of whether the person maintains an active Organization Report pursuant to §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements.)

(d) Any person using or maintaining a pit without the required permit shall be immediately required to cease usage and close the pit in accordance with §4.154 of this title (relating to Closure of Permitted Pits). Any person using or maintaining a pit without the required permit may be subject to enforcement action regardless of whether the person maintains an active Organization Report pursuant to §3.1 of this title.

(e) Permitted pits are subject to containment requirements to prevent pollution of surface or subsurface water and will be included as permit conditions at the sole discretion of the Commission.

(f) In the event of an unauthorized release of oil and gas waste, treated fluid, or other substances from any pit permitted by this subchapter, the operator shall take any measures necessary to stop or control the release and report the release to the District Office within 24 hours.

(g) Unless the Director approves a written request for an exception, no pit shall be located:

(1) on a barrier island or a beach;

(2) within 300 feet of surface water, including wetlands;

(3) within 500 feet of any public water system well or intake;

(4) within 300 feet of any domestic water well or irrigation water well, other than a well that supplies water for drilling or workover operations for which the pit is authorized;

(5) within a 100-year flood plain; or

(6) within 500 feet of a public area.

(h) A minimum 50-foot buffer zone shall be maintained between the boundaries of the property and the outer edge or toe of the pit walls or berms.

§4.152. Monitoring of Permitted Pits.

(a) A pit permit application shall include a monitoring plan that establishes a procedure for the permittee to routinely monitor the integrity of the liner of a pit. The permittee shall comply with this section by implementing one of the following monitoring methods.

(1) The permittee shall empty the pit and conduct a visual inspection on an annual basis. The permittee shall photograph the interior of the pit and otherwise record each inspection. The permittee shall maintain the photographs and records from each inspection for the life of the pit and supply these records to the Commission upon request.

(2) The permittee shall install a double liner and leak detection system between the primary and secondary liner. The leak detection system shall be monitored on a daily or weekly basis as specified in the permit to determine if the primary liner has failed.

(3) The permittee may implement an alternative monitoring procedure if the permittee demonstrates that the alternative monitoring is at least as protective of surface and subsurface waters as the procedures outlined in paragraphs (1) and (2) of this subsection and if the alternative monitoring procedure is approved by the Director.

(b) The permittee shall monitor all pits for liner failure in accordance with the monitoring plan approved by the Commission pursuant to subsection (a) of this section. The permittee shall consider the following when implementing the monitoring plan.

(1) Failure of the primary liner in a double liner and leak detection system occurs if:

(A) a volume of fluid is withdrawn from the leak detection system that is greater than the calculated action leakage rate, the standard action leakage rate of 1,000 gallons per acre per day (GPAD) for pits that manage fluid waste, or 100 gallons per acre per day (GPAD) for pits that manage solid oil and gas wastes;

(B) any failure in the leak detection and return system or any component of the system occurs; or

(C) any detected damage to or leakage from the secondary liner occurs.

(2) The failure of a liner system may be indicated through results of groundwater monitoring.

(3) If liner failure is discovered at any time, the permittee shall:

(A) notify the Director and the District Director by phone or email within 24 hours of the failure;

(B) coordinate subsequent response actions with the input and approval of the District Director; and

(C) mitigate the potential for a release from the pit.

(i) Except as provided in clause (ii) of this subparagraph, mitigation requires reducing the waste level to below the elevation of the liner failure and then repairing the liner. The permittee shall notify the District Director once the repair is complete. The District Director shall inspect the repair before the permittee may place the pit back in active operation.

(ii) For disposal pits, waste should not be removed. The permittee shall take other appropriate steps to prevent release or pollution. Any steps must be approved by the District Director. The permittee shall notify the District Director once the mitigation steps and repairs are complete. The District Director shall inspect the pit before the permittee may place the pit back in active operation.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Railroad Commission of Texas
Effective date: July 1, 2025
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For further information, please call: (512) 475-1295

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DIVISION 7. ADDITIONAL REQUIREMENTS FOR LANDFARMING AND LANDTREATING

16 TAC §§4.160 - 4.164

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.161. Design and Construction Requirements for Landfarming and Landtreating Permits.

(a) Application for landfarming and landtreating permits.

(1) The facility diagram submitted with the permit application shall include:

(A) two perpendicular, sectional views of all landfarming cells to be constructed, showing the bottom, sides, and dikes or berms of the cell with dimensions indicated; and

(B) the locations and dimensions of all areas where landfarming and landtreating will occur, dikes, well locations, fences, and access roads, taking into consideration the following restrictions:

(i) a minimum 50-foot buffer zone shall be maintained between the boundaries of the property and the treatment cells, measured from the toe of the constructed berm to the property boundary; and

(ii) a minimum 300-foot buffer zone shall be maintained between the toe of the constructed berms and any drainage features or surface waters.

(2) The applicant shall submit information to demonstrate that the area has at least 20 inches of tillable soil that is suitable for the application, treatment, and disposal of oil and gas waste.

(3) The applicant shall submit information sufficient for the Director to determine whether the proposed facility will pose a threat of pollution or a threat to public health or safety. The Director will consider the following factors when determining whether the proposed facility presents a threat of pollution or a threat to public health or safety:

(A) the volume and characteristics of the oil and gas waste to be managed at the landfarming facility;

(B) depth to and quality of the shallowest groundwater;

(C) distance to the nearest property line or public road;

(D) proximity to coastal natural resources, sensitive areas as defined by §4.110 of this title (relating to Definitions), water supplies, and/or public, domestic, or irrigation water wells; and

(E) any other factors reasonably necessary to determine whether issuance of the permit will pose a threat of pollution or a threat to public health or safety.

(b) Berm construction. All berms shall be constructed and maintained:

(1) to fully enclose each landfarming cell area;

(2) to a height of at least 36 inches above land surface with a slope no steeper than a one to three (vertical to horizontal) ratio on each side;

(3) so that at least two feet of freeboard plus capacity to contain the volume of precipitation from a 25-year, 24-hour rainfall event is available; and

(4) as otherwise required by the permit.

(c) Reasons for denial. The Director shall deny an application for a landfarming or landtreating permit if the proposed facility location is:

(1) within a 100-year flood plain;

(2) within 300 feet of surface water bodies;

(3) within 300 feet of domestic or irrigation water wells;

(4) within 500 feet of public water system wells or intakes;

(5) on unsuitable soils for depth or treatment of oil and gas waste;

(6) within any other sensitive area as defined by §4.110 of this title;

(7) within 500 feet of a public area; or

(8) non-compliant with Commission rules and permit conditions, as verified by a facility and records inspection.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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DIVISION 8. ADDITIONAL REQUIREMENTS FOR RECLAMATION PLANTS

16 TAC §§4.170 - 4.173

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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DIVISION 9. MISCELLANEOUS PERMITS

16 TAC §§4.180 - 4.182, 4.184, 4.185

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

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DIVISION 10. REQUIREMENTS FOR OIL AND GAS WASTE TRANSPORTATION

16 TAC §§4.190 - 4.195

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.190. Oil and Gas Waste Characterization and Documentation.

(a) The generator of oil and gas waste is responsible for characterizing and documenting the waste prior to transportation.

(b) A generator of any waste subject to Commission jurisdiction shall document the waste characterization by completing and retaining a Waste Profile Form that documents the characteristics of each waste stream generated.

(1) A Waste Profile Form shall be made available by the Commission or an operator may use its own form that includes at least the following information for each oil and gas waste stream:

(A) the generator name and P-5 operator number, including the contact information of the person preparing the waste profile;

(B) a generator-assigned identifier (name and/or number) specific to the generated waste;

(C) a description of the waste, including physical and chemical characteristics and constituents;

(D) the basis for the characterization, which shall be made in accordance with §4.102(a) of this title (relating to Responsibility for Oil and Gas Wastes); and

(E) other information pertinent to characterization.

(2) A generator may establish standard waste profiles for common types of oil and gas waste that are often found at oil and gas sites, such as spent water-based drilling mud, oil-based cuttings, oil-contaminated soil, domestic septage, and rubbish.

(3) A generator of waste that chooses to dispose of or recycle such waste shall provide the Waste Profile Form to the waste hauler and receiver.

(4) The receiver of the oil and gas waste shall include the waste profile information in the periodic reporting requirements as described in the facility permit conditions.

§4.191. Oil and Gas Waste Manifests.

(a) Oil and gas waste that is transported by vehicle from the lease, unit, or other oil or gas property or facility where it is generated to an off-lease facility that manages oil and gas waste shall:

(1) be accompanied by a paper manifest that meets the requirements of this section; or

(2) be documented and tracked by an electronic manifest system that meets the requirements of this section and is accessible to the Commission and all parties involved in the management of the waste.

(b) The Commission shall establish a standard oil and gas waste manifest that may be used in Texas, or operators may use their own forms provided they include at least the following information:

(1) identity of the waste generator, including operator name, Commission-issued operator number, and detailed contact information;

(2) identity of the property or facility where the oil and gas waste was generated, using Commission-issued identifiers including:

(A) operator name and Commission-assigned operator number of the generator;

(B) lease name and Commission-assigned lease number;

(C) facility name and Commission-assigned number, or the latitude and longitude of the waste origin if a Commission-assigned identifier is not available; and

(D) county name;

(3) the corresponding waste profile identifier prepared by the generator as required in §4.190 of this title (relating to Oil and Gas Waste Characterization and Documentation);

(4) identity of the facility to which the oil and gas waste is delivered including the identifier issued by the appropriate regulatory agency and detailed contact information for the facility;

(5) transporter name and waste hauler permit number with driver signature;

(6) type and volume of oil and gas waste transported;

(7) date of shipment;

(8) name and signature of generator; and

(9) date of acceptance with waste receiver signature.

(c) The generator of the oil and gas waste, the waste hauler, and the receiver shall keep for a period of three years from the date of shipment copies or electronic records of all manifests.

(d) Oil and gas waste that is moved by pipeline is not required to be accompanied by a manifest but an operator of an oil and gas waste pipeline system is required to:

(1) meter or document the fluid flow for mass balance into and out of the system;

(2) maintain the metering or documentation records for three years; and

(3) provide the records to the Commission upon request.

(e) A commercial facility receiver that refuses to accept a load of waste that is not correctly characterized or manifested shall notify Technical Permitting immediately. The notification shall include information necessary to identify the waste hauler and generator, if available.

§4.192. Trans-jurisdictional Waste Transfers.

(a) Section 3.30(e) of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)) provides a means by which certain RRC-jurisdictional waste may be managed at an appropriate TCEQ-regulated facility and by which certain TCEQ-jurisdictional waste may be managed at an appropriate RRC-regulated facility. Other statutes, rules, and permits may also authorize waste between jurisdictions.

(b) Waste transfers across jurisdictional authorities must be reported to the Commission beginning December 31, 2026.

(1) TCEQ-jurisdictional waste or waste from another jurisdiction being received by a Commission-regulated facility shall be reported as follows:

(A) If the receiving facility is required by permit or rule to file a quarterly report with the Commission, then the quarterly report must identify and quantify the waste received from other jurisdictions.

(B) If the receiving facility is not required by permit to file a quarterly report with the Commission, then the receiving facility shall file a monthly report within 30 days of the end of each calendar month in which non-jurisdictional waste was received. The monthly report shall summarize the identity and quantity of waste received from the other jurisdiction and shall include a copy of all waste manifests and waste characterization documentation.

(2) RRC-jurisdictional waste that is transferred to be managed at a facility regulated by TCEQ or another authority shall be reported to the Commission by the generator of the waste within 30 days of the waste transfer and shall include a copy of all waste manifests and waste characterization documentation.

(c) Beginning December 31, 2026, special waste authorization is required for all waste transfers that are not otherwise authorized by statute, rule, or permit. The generator of the waste is required to obtain the special waste authorization from the appropriate authorities.

(d) The Commission shall create a Special Waste Authorization Form suitable for these purposes.

§4.193. Oil and Gas Waste Haulers.

(a) Prohibitions. A person who transports oil and gas waste for hire by any method other than by pipeline shall not haul or dispose of oil and gas waste off a lease, unit, or other oil or gas property where it is generated without a valid oil and gas waste hauler permit. A permittee under this division shall not gather oil, gas, or geothermal resources unless otherwise authorized by Commission rules. An oil and gas waste hauler shall not transport oil, gas, or geothermal resources in the same vehicle being used to transport oil and gas wastes other than volumes of skim oil normally present in produced water or other oil and gas wastes.

(b) Exclusions.

(1) Hauling of inert waste, asbestos-containing material regulated under the Clean Air Act (42 USC §§7401 et seq.), polychlorinated biphenyl (PCB) waste regulated under the Toxic Substances Control Act (15 USC §§2601 et seq), or hazardous oil and gas waste subject to regulation under §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste) is excluded from this section.

(2) Hauling of oil and gas NORM waste that is not exempt from Subchapter F of this title (relating to Oil and Gas NORM) and that exceeds the exemption criteria specified in 25 Texas Administrative Code §289.259(d)(1), (2), and (3) (relating to Licensing of Naturally Occurring Radioactive Material (NORM)), is excluded from this section.

(c) Application. An application for an oil and gas waste hauler permit shall be made in an electronic system established by the Commission. The application shall include:

(1) the permit application fee required by §3.78 of this title (relating to Fees and Financial Security Requirements);

(2) vehicle identification information to support Commission issuance of an approved vehicle list;

(3) an affidavit from the operator of each commission-permitted waste facility the hauler intends to use stating that the hauler has permission to use the waste facility system;

(4) a certification by the hauler that the vehicles listed on the application are designed so that they will not leak during transportation. The certification shall include a statement that vehicles used to haul oil and gas waste are designed to transport oil and gas wastes and shall be operated and maintained to prevent the escape of oil and gas waste; and

(5) any other information required by the Commission.

(d) Permit term.

(1) An oil and gas waste hauler permit may be issued for a term not to exceed one year.

(2) A waste hauler permittee may not apply to renew a permit using the permittee's assigned permit number and by paying the fee required by §3.78 of this title until a minimum of 60 days before the expiration date specified in the permit.

(3) A waste hauler permittee shall apply for a new waste hauler permit number if the permittee submits a renewal application more than six months after the expiration of its permit.

(e) Permit conditions. Each oil and gas waste hauler shall operate in strict compliance with the instructions and conditions stated on the permit, which are restated as follows:

(1) This permit, unless suspended or revoked for cause shown, shall remain valid until the expiration date specified in this permit.

(2) Each vehicle used by a permittee shall be marked on both sides and the rear with the permittee's name and permit number in characters not less than three inches high. For the purposes of this permit, "vehicle" means any truck tank, trailer tank, tank car, vacuum truck, dump truck, garbage truck, or other container in which oil and gas waste will be hauled by the permittee.

(3) Each vehicle shall carry a copy of the permit including those parts of the Commission-issued attachments listing approved vehicles. This permit authority is limited to those vehicles shown on the Commission-issued list of approved vehicles.

(4) This permit is issued pursuant to the information furnished on the Commission-prescribed application form, and any change in conditions shall be reported to the Commission on an amended application form. The permit authority will be revised as required by the amended application.

(5) This permit authority is limited to hauling, handling, and disposal of oil and gas waste.

(6) This permit authorizes the permittee to use Commission-permitted waste facilities provided the waste facilities are permitted to receive the specific type of waste being hauled.

(7) This permit also authorizes the permittee to use a waste facility operated under authority of a minor permit issued by the Commission.

(8) This permit authorizes the permittee to transport hazardous oil and gas waste to any facility in accordance with the provisions of §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste) provided the shipment is accompanied by a manifest that meets the requirements of §3.98(o) or (w) of this title as applicable.

(9) This permit authorizes the transportation of non-hazardous oil and gas waste to a disposal facility permitted by another state agency, another state, or an agency of the federal government, provided the shipment is accompanied by a manifest, run ticket, or shipping paper and the person submits a copy of such manifest, run ticket, or shipping paper showing the information specified in §4.191 of this title (relating to Oil and Gas Waste Manifests) to the appropriate Commission District Office within 30 days of shipment.

(10) Each vehicle shall be operated and maintained at all times in such a manner as to prevent spillage, leakage, or other escape of oil and gas waste during transportation on or off any facility regulated by the Commission. Vehicles used to haul oil and gas waste shall be designed to transport oil and gas wastes and shall be operated and maintained to prevent the escape of oil and gas waste.

(11) Each vehicle shall be made available for inspection upon request by the Commission.

§4.195 Waste Originating Outside of Texas.

Oil and gas waste that is generated outside of Texas and transported into Texas by surface vehicle for management shall be accompanied by documentation including the name of the generator, the location of origin, and any operator and facility identifiers issued by the appropriate regulatory agency of that state to ensure the origin of the waste is accurately identified and possession of the waste is tracked.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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DIVISION 11. REQUIREMENTS FOR SURFACE WATER PROTECTION

16 TAC §4.196, §4.197

The Commission adopts the new rules pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.196. Surface Water Pollution Prevention.

(a) An operator shall not pollute the waters of the Texas offshore and adjacent estuarine zones (saltwater bearing bays, inlets, and estuaries) or damage aquatic life therein.

(b) All activities under the jurisdiction of the Commission shall be conducted in such a manner to preclude the pollution of the waters of the Texas offshore and adjacent estuarine zones. The following procedures shall be utilized to prevent pollution.

(1) No oil or other hydrocarbons in any form or combination with other materials or constituent shall be disposed of into the Texas offshore and adjacent estuarine zones.

(2) All deck areas on drilling platforms, barges, workover unit, and associated equipment both floating and stationary subject to contamination shall be either curbed and connected by drain to a collecting tank, sump, or enclosed drilling slot in which the containment will be treated and disposed of without causing hazard or pollution; or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans shall be piped to collecting tanks, sumps, or enclosed drilling slots to prevent overflow or prevent pollution of the surrounding water.

(3) Solid wastes such as cans, bottles, any form of trash, or ashes of combustible waste shall be transported to shore in appropriate containers.

(4) Drilling muds which contain oil shall be transported to shore or a designated area for disposal.

(5) Fluids produced from offshore wells shall be mechanically contained in adequately pressure-controlled piping or vessels from producing well to disposition point. Oil and water separation facilities at offshore and onshore locations shall contain safeguards to prevent discharge of pollutants to the Texas offshore and adjacent estuarine zones.

(6) Any person observing water pollution shall report such sighting, noting size, material, location, and current conditions to the ranking operating personnel. Immediate action shall be taken or notification made to eliminate further pollution. The operator shall then transmit the report to the appropriate Commission District Office.

(7) Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator.

(c) The Commission may suspend producing and/or drilling operations from any facility if the provisions of this rule are being violated.

(d) The requirements of this section shall also apply to all oil, gas, or geothermal resource operations conducted on the inland and fresh waters of the State of Texas, such as lakes, rivers, and streams.

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SUBCHAPTER B. COMMERCIAL RECYCLING

DIVISION 1. GENERAL; DEFINITIONS

16 TAC §§4.201 - 4.209, 4.211

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

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Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.203. Responsibility for Management of Waste to be Recycled.

(a) Permit required. A person who operates a commercial recycling facility shall obtain a permit from the Commission under this subchapter before engaging in such operation.

(b) Hauling of waste. A waste hauler transporting and delivering oil and gas waste for commercial recycling permitted pursuant to this subchapter shall be permitted by the Commission as an Oil and Gas Waste Hauler pursuant to §4.193 of this title (relating to Oil and Gas Waste Haulers).

(c) Responsibility of generator and carrier. No generator or carrier may knowingly use the services of a commercial recycling facility unless the facility has a permit issued under this subchapter. A person who uses the services of a commercial recycling facility has a duty to determine that the commercial recycling facility has all permits required by statute or Commission rule.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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For further information, please call: (512) 475-1295

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DIVISION 2. REQUIREMENTS FOR ON-LEASE COMMERCIAL SOLID OIL AND GAS WASTE RECYCLING

16 TAC §§4.212 - 4.214, 4.218 - 4.224

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.219. Minimum Siting Information.

(a) A permit for on-lease commercial solid oil and gas waste recycling may be issued only if the Director or the Commission determines that the operations will pose no unreasonable risk of pollution or threat to public health or safety.

(b) A pit permitted pursuant to this division is prohibited:

(1) within a 100-year flood plain;

(2) within a sensitive area as defined by §4.110 of this title (relating to Definitions);

(3) within 300 feet of surface water, domestic supply wells, or irrigation water wells;

(4) within 500 feet of any public water system wells or intakes;

(5) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL) tested using fluids likely to be encountered in the operations of the facility and the test results demonstrated the GCL can sustain a hydraulic conductivity of 1.0 x 10-7cm/sec or less;

(6) within 1,000 feet of a permanent residence, school, hospital, institution, or church in existence at the time of initial permitting; or

(7) within 500 feet of a wetland.

(c) A permit application for on-lease commercial solid oil and gas waste recycling shall include:

(1) a description of the proposed facility site and surrounding area;

(2) the name, physical address and, if different, mailing address, and telephone number of every owner of the tract on which the facility is to be located. If any owner is not an individual, the applicant shall include the name of a contact person for that owner;

(3) the depth to the shallowest subsurface water and the direction of groundwater flow at the proposed site, and the source of this information;

(4) the average annual precipitation and evaporation at the proposed site and the source of this information;

(5) the identification of the soil and subsoil by typical name and description of the approximate proportion of grain sizes, texture, consistency, moisture condition, and other pertinent characteristics, and the source of this information;

(6) a copy of a county highway map with a scale and north arrow showing the location of the proposed facility; and

(7) a United States Geological Survey (USGS) topographic map or an equivalent topographic map which shows the facility including the items listed in subparagraphs (A) - (K) of this paragraph and any other pertinent information regarding the regulated facility and associated activities. Maps shall be on a scale of not less than one inch equals 2,000 feet. The map shall show the following:

(A) a scale and north arrow showing the tract size in square feet or acres, the section/survey lines, and the survey name and abstract number;

(B) a clear outline of the proposed facility's boundaries;

(C) the location of any pipelines within 500 feet of the facility;

(D) the distance from the facility's outermost perimeter boundary to public and private water wells, residences, schools, churches, and hospitals that are within 500 feet of the boundary;

(E) for disposal only, the location of all residential and commercial buildings within a one-mile radius of the facility boundary;

(F) all water wells within a one-mile radius of the facility boundary;

(G) the location of the 100-year flood plain and the source of the flood plain information;

(H) surface water bodies within the map area;

(I) the location of any major and minor aquifers within the map area;

(J) the boundaries of any prohibited areas defined under §4.153 of this title (relating to Commercial Disposal Pits); and

(K) any other information requested by the Director reasonably related to the prevention of pollution.

(d) Factors that the Commission will consider in assessing potential risk from on-lease commercial solid oil and gas waste recycling include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) proximity to coastal natural resources or sensitive areas as defined by §4.110 of this title; and

(3) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(e) All siting requirements in this section for on-lease commercial solid oil and gas waste recycling refer to conditions at the time the equipment and tanks used in the recycling are placed.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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DIVISION 3. REQUIREMENTS FOR OFF-LEASE OR CENTRALIZED COMMERCIAL SOLID OIL AND GAS WASTE RECYCLING

16 TAC §§4.230 - 4.232, 4.234, 4.238 - 4.243, 4.245

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.232. Minimum Siting Information.

(a) A permit application for off-lease or centralized commercial solid oil and gas waste recycling shall include:

(1) a description of the proposed facility site and surrounding area;

(2) the name, physical address and, if different, mailing address, and telephone number of every owner of the tract on which the facility is to be located. If any owner is not an individual, the applicant shall include the name of a contact person for that owner;

(3) the depth to the shallowest subsurface water and the direction of groundwater flow at the proposed site, and the source of this information;

(4) the average annual precipitation and evaporation at the proposed site and the source of this information;

(5) the identification of the soil and subsoil by typical name and description of the approximate proportion of grain sizes, texture, consistency, moisture condition, and other pertinent characteristics, and the source of this information;

(6) a copy of a county highway map with a scale and north arrow showing the location of the proposed facility; and

(7) a United States Geological Survey (USGS) topographic map or an equivalent topographic map which shows the facility including the items listed in subparagraphs (A) - (K) of this paragraph and any other pertinent information regarding the regulated facility and associated activities. Maps shall be on a scale of not less than one inch equals 2,000 feet. The map shall show the following:

(A) a scale and north arrow showing the tract size in square feet or acres, the section/survey lines, and the survey name and abstract number;

(B) a clear outline of the proposed facility's boundaries;

(C) the location of any pipelines within 500 feet of the facility;

(D) the distance from the facility's outermost perimeter boundary to public and private water wells, residences, schools, churches, and hospitals that are within 500 feet of the boundary;

(E) for disposal only, the location of all residential and commercial buildings within a one-mile radius of the facility boundary;

(F) all water wells within a one-mile radius of the facility boundary;

(G) the location of the 100-year flood plain and the source of the flood plain information;

(H) surface water bodies within the map area;

(I) the location of any major and minor aquifers within the map area;

(J) the boundaries of any prohibited areas defined under §4.153 of this title (relating to Commercial Disposal Pits); and

(K) any other information requested by the Director reasonably related to the prevention of pollution.

(b) A pit permitted pursuant to this division is prohibited:

(1) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL) tested using fluids likely to be encountered in the operations of the facility and the test results demonstrated the GCL can sustain a hydraulic conductivity of 1.0 x 10-7cm/sec or less;

(2) within a sensitive area as defined by §4.110 of this title (relating to Definitions);

(3) within 300 feet of surface water, domestic supply wells, or irrigation water wells;

(4) within 500 feet of any public water system wells or intakes;

(5) within 1,000 feet of a permanent residence, school, hospital, institution, or church in existence at the time of the initial permitting;

(6) within 500 feet of a wetland; or

(7) within a 100-year floodplain.

(c) Factors that the Commission will consider in assessing potential risk from on off-lease or centralized commercial solid oil and gas waste recycling include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste, and recyclable product to be stored, handled, treated and recycled at the facility;

(2) proximity to coastal natural resources or sensitive areas as defined by §4.110 of this title; and

(3) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section for on-lease off-lease or centralized commercial solid oil and gas waste recycling refer to conditions at the time the equipment and tanks used in the recycling are placed.

§4.238. Notice.

(a) Purpose. Applicants are encouraged to engage with their communities early in the commercial recycling facility planning process to inform the community of the plan to construct an off-lease or centralized commercial solid oil and gas waste recycling facility and allow those who may be affected by the proposed activities to express their concerns. The purpose of the notice required by this section is to inform notice recipients:

(1) that an applicant has filed a permit application with the Commission, seeking authorization to conduct an activity or operate a facility; and

(2) of the requirements for filing a protest if an affected person seeks to protest the permit application.

(b) Timing of notice. The applicant shall provide notice after staff determines that an application for an off-lease or centralized commercial solid oil and gas waste recycling facility is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively). The date notice is completed begins a 30-day period in which an affected person may file a protest of the application with the Commission.

(c) Notice recipients. The applicant shall provide notice to:

(1) the surface owners of the tract on which the commercial recycling facility will be located;

(2) the surface owners of tracts located within a distance of 1/2-mile from the fence line or edge of the facility as shown on the plat required under §4.233(b) of this title (relating to Minimum Real Property Information) of the facility's fence line or boundary, even if the surface owner's tract is not adjacent to the tract on which the commercial recycling facility is located;

(3) the city clerk or other appropriate city official if any part of the tract on which the commercial recycling facility will be located lies within the municipal boundaries of the city;

(4) the Commission's District Office; and

(5) any other person or class of persons that the Director determines should receive notice of an application.

(d) Method and contents of notice. Unless otherwise specified in this subchapter, the applicant shall provide direct notice to the persons specified in subsection (c) of this section as follows.

(1) The applicant shall provide notice by registered or certified mail. Notice is completed upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

(2) The notice of the permit application shall consist of a complete copy of the application and any attachments. The copy shall be of the application and attachments after staff determines the application is complete pursuant to §1.201(b) of this title but before the final review is completed.

(3) The notice shall include a letter that contains:

(A) the name of the applicant;

(B) the date of the notice;

(C) the name of the surface owners of the tract on which the proposed commercial recycling facility will be located;

(D) the location of the tract on which the proposed commercial recycling facility will be located including a legal description of the tract, latitude/longitude coordinates of the proposed facility, county, original survey, abstract number, and the direction and distance from the nearest municipality or community;

(E) the types of solids to be recycled at the commercial recycling facility;

(F) the recycling method proposed and the proposed end-use of the recycled material;

(G) a statement that an affected person may protest the application by filing a written protest with the Commission within 30 calendar days of the date notice is completed;

(H) a statement that a protest shall include the protestant's name, mailing address, telephone number, and email address;

(I) the address to which protests may be mailed or the location and instructions for electronic submittal of a protest if the Commission implements an electronic means for filing protests;

(J) the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(K) the signature of the operator, or representative of the operator, and the date the letter was signed.

(4) If the Director finds that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

(e) Proof of notice. After the applicant provides the notice required by this section, the applicant shall submit to the Commission proof of delivery of notice which shall consist of:

(1) a copy of the signed and dated letters required by subsection (d)(3) of this section;

(2) the registered or certified mail receipts; and

(3) a map showing the property boundaries, surface owner names, and parcel numbers of all notified parties.

(f) Protest process. Any statement of protest to an application must be filed with the Commission within 30 calendar days from the date notice is completed or from the last date of publication if notice by publication is authorized by the Director.

(1) The Technical Permitting Section shall notify the applicant if the Commission receives an affected person's timely protest. A timely protest is a written protest date-stamped as received by the Commission within 30 calendar days of the date notice is completed.

(2) The applicant shall have 30 days from the date of the Technical Permitting Section's notice of receipt of protest to respond, in writing, by either requesting a hearing or withdrawing the application. If the applicant fails to timely file a written response, the Technical Permitting Section shall consider the application to have been withdrawn.

(3) The Technical Permitting Section shall refer all protested applications to the Hearings Division if a timely protest is received and the applicant requests a hearing.

(4) The Commission shall provide notice of any hearing convened under this subsection to all affected persons and persons who have requested notice of the hearing.

(5) If the Director has reason to believe that a person entitled to notice of an application has not received notice as required by this section, then the Technical Permitting Section shall not take action on the application until notice is provided to such person.

(6) The Commission may issue a permit if no timely protests from affected persons are received.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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DIVISION 4. REQUIREMENTS FOR STATIONARY COMMERCIAL SOLID OIL AND GAS WASTE RECYCLING FACILITIES

16 TAC §§4.246 - 4.248, 4.250, 4.251, 4.254 - 4.259, 4.261

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.248. Minimum Siting Information.

(a) A permit application for a stationary commercial solid oil and gas waste recycling facility shall include:

(1) a description of the proposed facility site and surrounding area;

(2) the name, physical address and, if different, mailing address, and telephone number of every owner of the tract on which the facility is to be located. If any owner is not an individual, the applicant shall include the name of a contact person for that owner;

(3) the depth to the shallowest subsurface water and the direction of groundwater flow at the proposed site, and the source of this information;

(4) the average annual precipitation and evaporation at the proposed site and the source of this information;

(5) the identification of the soil and subsoil by typical name and description of the approximate proportion of grain sizes, texture, consistency, moisture condition, and other pertinent characteristics, and the source of this information;

(6) a copy of a county highway map with a scale and north arrow showing the location of the proposed facility; and

(7) a United States Geological Survey (USGS) topographic map or an equivalent topographic map which shows the facility including the items listed in subparagraphs (A) - (K) of this paragraph and any other pertinent information regarding the regulated facility and associated activities. Maps shall be on a scale of not less than one inch equals 2,000 feet. The map shall show the following:

(A) a scale and north arrow showing the tract size in square feet or acres, the section/survey lines, and the survey name and abstract number;

(B) a clear outline of the proposed facility's boundaries;

(C) the location of any pipelines within 500 feet of the facility;

(D) the distance from the facility's outermost perimeter boundary to public and private water wells, residences, schools, churches, and hospitals that are within 500 feet of the boundary;

(E) for disposal only, the location of all residential and commercial buildings within a one-mile radius of the facility boundary;

(F) all water wells within a one-mile radius of the facility boundary;

(G) the location of the 100-year flood plain and the source of the flood plain information;

(H) surface water bodies within the map area;

(I) the location of any major and minor aquifers within the map area;

(J) the boundaries of any prohibited areas defined under §4.153 of this title (relating to Commercial Disposal Pits); and

(K) any other information requested by the Director reasonably related to the prevention of pollution.

(b) A pit permitted under this division is prohibited:

(1) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL) tested using fluids likely to be encountered in the operations of the facility and the test results demonstrated the GCL can sustain a hydraulic conductivity of 1.0 x 10-7cm/sec or less;

(2) within a sensitive area as defined by §4.110 of this title (relating to Definitions);

(3) within 300 feet of surface water, domestic supply wells, or irrigation water wells;

(4) within 500 feet of any public water system wells or intakes;

(5) within 1,000 feet of a permanent residence, school, hospital, institution, or church in existence at the time of the initial permitting;

(6) within 500 feet of a wetland; or

(7) within a 100-year floodplain.

(c) Factors that the Commission will consider in assessing potential risk from stationary commercial solid oil and gas waste recycling include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) proximity to coastal natural resources or sensitive areas as defined by §4.110 of this title; and

(3) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section for stationary commercial solid oil and gas waste recycling refer to conditions at the time the equipment and tanks used in the recycling are placed.

§4.254. Notice.

(a) Purpose. Applicants are encouraged to engage with their communities early in the commercial recycling facility planning process to inform the community of the plan to construct stationary commercial solid oil and gas waste recycling facility and allow those who may be affected by the proposed activities to express their concerns. The purpose of the notice required by this section is to inform notice recipients:

(1) that an applicant has filed a permit application with the Commission, seeking authorization to conduct an activity or operate a facility; and

(2) of the requirements for filing a protest if an affected person seeks to protest the permit application.

(b) Timing of notice. The applicant shall provide notice after staff determines that an application for a stationary commercial solid oil and gas waste recycling facility is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively). The date notice is completed begins a 30-day period in which an affected person may file a protest of the application with the Commission.

(c) Notice recipients. The applicant shall provide notice to:

(1) the surface owners of the tract on which the commercial recycling facility will be located;

(2) the surface owners of tracts located within a distance of 1/2-mile from the fence line or edge of the facility as shown on the plat required under §4.249(b) of this title (relating to Minimum Real Property Information) of the facility's fence line or boundary, even if the surface owner's tract is not adjacent to the tract on which the commercial recycling facility is located;

(3) the city clerk or other appropriate city official if any part of the tract on which the commercial recycling facility will be located lies within the municipal boundaries of the city;

(4) the Commission's District Office; and

(5) any other person or class of persons that the Director determines should receive notice of an application.

(d) Method and contents of notice. Unless otherwise specified in this subchapter, the applicant shall provide direct notice to the persons specified in subsection (c) of this section as follows.

(1) The applicant shall provide notice by registered or certified mail. Notice is completed upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

(2) The notice of the permit application shall consist of a complete copy of the application and any attachments. The copy shall be of the application and attachments after staff determines the application is complete pursuant to §1.201(b) of this title but before the final review is completed.

(3) The notice shall include a letter that contains:

(A) the name of the applicant;

(B) the date of the notice;

(C) the name of the surface owners of the tract on which the proposed commercial recycling facility will be located;

(D) the location of the tract on which the proposed commercial recycling facility will be located including a legal description of the tract, latitude/longitude coordinates of the proposed facility, county, original survey, abstract number, and the direction and distance from the nearest municipality or community;

(E) the types of solids to be recycled at the commercial recycling facility;

(F) the recycling method proposed and the proposed end-use of the recycled material;

(G) a statement that an affected person may protest the application by filing a written protest with the Commission within 30 calendar days of the date notice is completed;

(H) a statement that a protest shall include the protestant's name, mailing address, telephone number, and email address;

(I) the address to which protests may be mailed or the location and instructions for electronic submittal of a protest if the Commission implements an electronic means for filing protests;

(J) the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(K) the signature of the operator, or representative of the operator, and the date the letter was signed.

(4) If the Director finds that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

(e) Proof of notice. After the applicant provides the notice required by this section, the applicant shall submit to the Commission proof of delivery of notice which shall consist of:

(1) a copy of the signed and dated letters required by subsection (d)(3) of this section;

(2) the registered or certified mail receipts; and

(3) a map showing the property boundaries, surface owner names, and parcel numbers of all notified parties.

(f) Notice by publication. In addition to the notice required by subsection (d) of this section, an applicant for a stationary commercial solid oil and gas waste recycling commercial facility permit shall also provide notice by publication.

(g) Newspaper of general circulation. The permit applicant shall publish notice of the application in a newspaper of general circulation in the county in which the proposed facility will be located at least once each week for two consecutive weeks, with the first publication occurring not earlier than the date staff determines that an application is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively) but before the final review is completed.

(h) Contents of published notice. The published notice shall:

(1) be entitled "Notice of Application for Commercial Solid Oil and Gas Waste Recycling Facility" if the proposed facility is a commercial facility;

(2) provide the date the applicant filed the application with the Commission;

(3) identify the name of the applicant;

(4) provide the location of the tract on which the proposed facility will be located including the legal description of the property, latitude/longitude coordinates of the proposed facility, county, name of the original survey and abstract number, and location and distance in relation to the nearest municipality or community;

(5) identify the owner or owners of the property on which the proposed facility will be located;

(6) identify the type of fluid or solid waste to be managed at the facility;

(7) identify the proposed recycling method;

(8) state that affected persons may protest the application by filing a protest with the Commission within 30 calendar days of the last date of publication;

(9) include the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(10) provide the address to which protests shall be mailed. If the Commission implements an electronic means for filing protests, then the location to instructions for electronic submittal shall be included.

(i) Proof of notice. The applicant shall submit to the Commission proof that notice was published as required by this section. Proof of publication shall consist of:

(1) an affidavit from the newspaper publisher that states the dates on which the notice was published and the county or counties in which the newspaper is of general circulation; and

(2) the tear sheets for each published notice.

(j) Protest process. Any statement of protest to an application must be filed with the Commission within 30 calendar days from the date notice is completed or from the last date of publication if notice by publication is authorized by the Director.

(1) The Technical Permitting Section shall notify the applicant if the Commission receives an affected person's timely protest. A timely protest is a written protest date-stamped as received by the Commission within 30 calendar days of the date notice is completed or within 30 calendar days of the last date of publication, whichever is later.

(2) The applicant shall have 30 days from the date of the Technical Permitting Section's notice of receipt of protest to respond, in writing, by either requesting a hearing or withdrawing the application. If the applicant fails to timely file a written response, the Technical Permitting Section shall consider the application to have been withdrawn.

(3) The Technical Permitting Section shall refer all protested applications to the Hearings Division if a timely protest is received and the applicant requests a hearing.

(4) The Commission shall provide notice of any hearing convened under this subsection to all affected persons and persons who have requested notice of the hearing.

(5) If the Director has reason to believe that a person entitled to notice of an application has not received notice as required by this section, then the Technical Permitting Section shall not take action on the application until notice is provided to such person.

(6) The Commission may issue a permit if no timely protests from affected persons are received.

(k) Director review. If the Director has reason to believe that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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For further information, please call: (512) 475-1295

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DIVISION 5. REQUIREMENTS FOR OFF-LEASE COMMERCIAL RECYCLING OF FLUID

16 TAC §§4.262 - 4.264, 4.266 - 4.277

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.264. Minimum Siting Information.

(a) A pit permitted under this division is prohibited:

(1) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL) tested using fluids likely to be encountered in the operations of the facility and the test results demonstrated the GCL can sustain a hydraulic conductivity of 1.0 x 10-7cm/sec or less;

(2) within a sensitive area as defined by §4.110 of this title (relating to Definitions);

(3) within 300 feet of surface water, domestic supply wells, or irrigation water wells;

(4) within 500 feet of any public water system wells or intakes;

(5) within 1,000 feet of a permanent residence, school, hospital, institution, or church in existence at the time of the initial permitting;

(6) within 500 feet of a wetland; or

(7) within a 100-year floodplain.

(b) A permit application for off-lease commercial recycling of fluid shall include:

(1) a description of the proposed facility site and surrounding area;

(2) the name, physical address and, if different, mailing address, and telephone number of every owner of the tract on which the

facility is to be located. If any owner is not an individual, the applicant shall include the name of a contact person for that owner;

(3) the depth to the shallowest subsurface water and the direction of groundwater flow at the proposed site, and the source of this information;

(4) the average annual precipitation and evaporation at the proposed site and the source of this information;

(5) the identification of the soil and subsoil by typical name and description of the approximate proportion of grain sizes, texture, consistency, moisture condition, and other pertinent characteristics, and the source of this information;

(6) a copy of a county highway map with a scale and north arrow showing the location of the proposed facility; and

(7) a United States Geological Survey (USGS) topographic map or an equivalent topographic map which shows the facility including the items listed in subparagraphs (A)-(K) of this paragraph and any other pertinent information regarding the regulated facility and associated activities. Maps shall be on a scale of not less than one inch equals 2,000 feet. The map shall show the following:

(A) a scale and north arrow showing the tract size in square feet or acres, the section/survey lines, and the survey name and abstract number;

(B) a clear outline of the proposed facility's boundaries;

(C) the location of any pipelines within 500 feet of the facility;

(D) the distance from the facility's outermost perimeter boundary to public and private water wells, residences, schools, churches, and hospitals that are within 500 feet of the boundary;

(E) for disposal only, the location of all residential and commercial buildings within a one-mile radius of the facility boundary;

(F) all water wells within a one-mile radius of the facility boundary;

(G) the location of the 100-year flood plain and the source of the flood plain information;

(H) surface water bodies within the map area;

(I) the location of any major and minor aquifers within the map area;

(J) the boundaries of any prohibited areas defined under §4.153 of this title (relating to Commercial Disposal Pits); and

(K) any other information requested by the Director reasonably related to the prevention of pollution.

(c) Factors that the Commission will consider in assessing potential risk from off-lease commercial recycling of fluid include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) proximity to coastal natural resources or sensitive areas as defined by §4.110 of this title; and

(3) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section for off-lease commercial recycling of fluid refer to conditions at the time the equipment and tanks used in the recycling are placed.

§4.270. Notice.

(a) Purpose. Applicants are encouraged to engage with their communities early in the commercial recycling facility planning process to inform the community of the plan to construct a facility for off-lease commercial recycling of facility and allow those who may be affected by the proposed activities to express their concerns. The purpose of the notice required by this section is to inform notice recipients:

(1) that an applicant has filed a permit application with the Commission, seeking authorization to conduct an activity or operate a facility; and

(2) of the requirements for filing a protest if an affected person seeks to protest the permit application.

(b) Timing of notice. The applicant shall provide notice after staff determines that an application for a facility for off-lease commercial recycling of fluid is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively). The date notice is completed begins a 30-day period in which an affected person may file a protest of the application with the Commission.

(c) Notice recipients. The applicant shall provide notice to:

(1) the surface owners of the tract on which the commercial recycling facility will be located;

(2) the surface owners of tracts located within a distance of 1/2-mile from the fence line or edge of the facility as shown on the plat required under §4.265(b) of this title (relating to Minimum Real Property Information) of the facility's fence line or boundary, even if the surface owner's tract is not adjacent to the tract on which the commercial recycling facility is located.

(3) the city clerk or other appropriate city official if any part of the tract on which the commercial recycling facility will be located lies within the municipal boundaries of the city;

(4) the Commission's District Office; and

(5) any other person or class of persons that the Director determines should receive notice of an application.

(d) Method and contents of notice. Unless otherwise specified in this subchapter, the applicant shall provide direct notice to the persons specified in subsection (c) of this section as follows.

(1) The applicant shall provide notice by registered or certified mail. Notice is completed upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

(2) The notice of the permit application shall consist of a complete copy of the application and any attachments. The copy shall be of the application and attachments after staff determines the application is complete pursuant to §1.201(b) of this title but before the final review is completed.

(3) The notice shall include a letter that contains:

(A) the name of the applicant;

(B) the date of the notice;

(C) the name of the surface owners of the tract on which the proposed commercial recycling facility will be located;

(D) the location of the tract on which the proposed commercial recycling facility will be located including a legal description of the tract, latitude/longitude coordinates of the proposed facility, county, original survey, abstract number, and the direction and distance from the nearest municipality or community;

(E) the types of fluids to be recycled at the commercial recycling facility;

(F) the recycling method proposed and the proposed end-use of the recycled material;

(G) a statement that an affected person may protest the application by filing a written protest with the Commission within 30 calendar days of the date notice is completed;

(H) a statement that a protest shall include the protestant's name, mailing address, telephone number, and email address;

(I) the address to which protests may be mailed or the location and instructions for electronic submittal of a protest if the Commission implements an electronic means for filing protests;

(J) the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(K) the signature of the operator, or representative of the operator, and the date the letter was signed.

(4) If the Director finds that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

(e) Proof of notice. After the applicant provides the notice required by this section, the applicant shall submit to the Commission proof of delivery of notice which shall consist of:

(1) a copy of the signed and dated letters required by subsection (d)(3) of this section;

(2) the registered or certified mail receipts; and

(3) a map showing the property boundaries, surface owner names, and parcel numbers of all notified parties.

(f) Protest process. Any statement of protest to an application must be filed with the Commission within 30 calendar days from the date notice is completed or from the last date of publication if notice by publication is authorized by the Director.

(1) The Technical Permitting Section shall notify the applicant if the Commission receives an affected person's timely protest. A timely protest is a written protest date-stamped as received by the Commission within 30 calendar days of the date notice is completed.

(2) The applicant shall have 30 days from the date of the Technical Permitting Section's notice of receipt of protest to respond, in writing, by either requesting a hearing or withdrawing the application. If the applicant fails to timely file a written response, the Technical Permitting Section shall consider the application to have been withdrawn.

(3) The Technical Permitting Section shall refer all protested applications to the Hearings Division if a timely protest is received and the applicant requests a hearing.

(4) The Commission shall provide notice of any hearing convened under this subsection to all affected persons and persons who have requested notice of the hearing.

(5) If the Director has reason to believe that a person entitled to notice of an application has not received notice as required by this section, then the Technical Permitting Section shall not take action on the application until notice is provided to such person.

(6) The Commission may issue a permit if no timely protests from affected persons are received.

§4.272. Minimum Permit Provisions for Siting.

(a) A permit for off-lease commercial recycling of fluid may be issued only if the Director or the Commission determines that the facility is to be located in an area where there is no unreasonable risk of pollution or threat to public health or safety.

(b) Off-lease commercial recycling of fluid permitted pursuant to this division is prohibited:

(1) within a 100-year flood plain, in a streambed, or in a sensitive area as defined by §4.110 of this title (relating to Definitions); or

(2) within 300 feet of surface water or public, domestic, or irrigation water wells.

(c) Factors that the Commission will consider in assessing potential risk from off-lease commercial recycling of fluid include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) distance to any surface water body, wet or dry;

(3) depth to and quality of the shallowest groundwater;

(4) distance to the nearest property line or public road;

(5) proximity to coastal natural resources, sensitive areas as defined by §4.110 of this title, or water supplies, and/or public, domestic, or irrigation water wells; and

(6) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section refer to conditions at the time the facility is constructed.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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DIVISION 6. REQUIREMENTS FOR STATIONARY COMMERCIAL RECYCLING OF FLUID

16 TAC §§4.278 - 4.280, 4.282 - 4.293

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.280. Minimum Siting Information.

(a) A pit permitted under this division shall not be located:

(1) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL) tested using fluids likely to be encountered in the operations of the facility and the test results demonstrated the GCL can sustain a hydraulic conductivity of 1.0 x 10-7cm/sec or less;

(2) within a sensitive area as defined by §4.110 of this title (relating to Definitions);

(3) within 300 feet of surface water, domestic supply wells, or irrigation water wells;

(4) within 500 feet of any public water system wells or intakes.

(5) within 1,000 feet of a permanent residence, school, hospital, institution, or church in existence at the time of the initial permitting;

(6) within 500 feet of a wetland; or

(7) within a 100-year floodplain.

(b) A permit application for a stationary commercial fluid recycling facility shall include:

(1) a description of the proposed facility site and surrounding area;

(2) the name, physical address and, if different, mailing address, and telephone number of every owner of the tract on which the facility is to be located. If any owner is not an individual, the applicant shall include the name of a contact person for that owner;

(3) the depth to the shallowest subsurface water and the direction of groundwater flow at the proposed site, and the source of this information;

(4) the average annual precipitation and evaporation at the proposed site and the source of this information;

(5) the identification of the soil and subsoil by typical name and description of the approximate proportion of grain sizes, texture, consistency, moisture condition, and other pertinent characteristics, and the source of this information;

(6) a copy of a county highway map with a scale and north arrow showing the location of the proposed facility; and

(7) a United States Geological Survey (USGS) topographic map or an equivalent topographic map which shows the facility including the items listed in subparagraphs (A) - (K) of this paragraph and any other pertinent information regarding the regulated facility and associated activities. Maps shall be on a scale of not less than one inch equals 2,000 feet. The map shall show the following:

(A) a scale and north arrow showing the tract size in square feet or acres, the section/survey lines, and the survey name and abstract number;

(B) a clear outline of the proposed facility's boundaries;

(C) the location of any pipelines within 500 feet of the facility;

(D) the distance from the facility's outermost perimeter boundary to public and private water wells, residences, schools, churches, and hospitals that are within 500 feet of the boundary;

(E) for disposal only, the location of all residential and commercial buildings within a one-mile radius of the facility boundary;

(F) all water wells within a one-mile radius of the facility boundary;

(G) the location of the 100-year flood plain and the source of the flood plain information;

(H) surface water bodies within the map area;

(I) the location of any major and minor aquifers within the map area;

(J) the boundaries of any prohibited areas defined under §4.153 of this title (relating to Commercial Disposal Pits); and

(K) any other information requested by the Director reasonably related to the prevention of pollution.

(c) Factors that the Commission will consider in assessing potential risk from stationary commercial fluid recycling include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) proximity to coastal natural resources or sensitive areas as defined by §4.110 of this title; and

(3) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section for stationary commercial fluid recycling refer to conditions at the time the equipment and tanks used in the recycling are placed.

§4.286. Notice.

(a) Purpose. Applicants are encouraged to engage with their communities early in the commercial recycling facility planning process to inform the community of the plan to construct stationary commercial fluid recycling facility and allow those who may be affected by the proposed activities to express their concerns. The purpose of the notice required by this section is to inform notice recipients:

(1) that an applicant has filed a permit application with the Commission, seeking authorization to conduct an activity or operate a facility; and

(2) of the requirements for filing a protest if an affected person seeks to protest the permit application.

(b) Timing of notice. The applicant shall provide notice after staff determines that an application stationary commercial fluid recycling facility is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively). The date notice is completed begins a 30-day period in which an affected person may file a protest of the application with the Commission.

(c) Notice recipients. The applicant shall provide notice to:

(1) the surface owners of the tract on which the commercial recycling facility will be located;

(2) the surface owners of tracts located within a distance of 1/2-mile from the fence line or edge of the facility as shown on the plat required under §4.249(b) of this title (relating to Minimum Real Property Information) of the facility's fence line or boundary, even if the surface owner's tract is not adjacent to the tract on which the commercial recycling facility is located;

(3) the city clerk or other appropriate city official if any part of the tract on which the commercial recycling facility will be located lies within the municipal boundaries of the city;

(4) the Commission's District Office; and

(5) any other person or class of persons that the Director determines should receive notice of an application.

(d) Method and contents of notice. Unless otherwise specified in this subchapter, the applicant shall provide direct notice to the persons specified in subsection (c) of this section as follows.

(1) The applicant shall provide notice by registered or certified mail. Notice is completed upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service.

(2) The notice of the permit application shall consist of a complete copy of the application and any attachments. The copy shall be of the application and attachments after staff determines the application is complete pursuant to §1.201(b) of this title but before the final review is completed.

(3) The notice shall include a letter that contains:

(A) the name of the applicant;

(B) the date of the notice;

(C) the name of the surface owners of the tract on which the proposed commercial recycling facility will be located;

(D) the location of the tract on which the proposed commercial recycling facility will be located including a legal description of the tract, latitude/longitude coordinates of the proposed facility, county, original survey, abstract number, and the direction and distance from the nearest municipality or community;

(E) the types of fluids to be recycled at the commercial recycling facility;

(F) the recycling method proposed and the proposed end-use of the recycled material;

(G) a statement that an affected person may protest the application by filing a written protest with the Commission within 30 calendar days of the date notice is completed;

(H) a statement that a protest shall include the protestant's name, mailing address, telephone number, and email address;

(I) the address to which protests may be mailed or the location and instructions for electronic submittal of a protest if the Commission implements an electronic means for filing protests;

(J) the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(K) the signature of the operator, or representative of the operator, and the date the letter was signed.

(4) If the Director finds that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

(e) Proof of notice. After the applicant provides the notice required by this section, the applicant shall submit to the Commission proof of delivery of notice which shall consist of:

(1) a copy of the signed and dated letters required by subsection (d)(3) of this section;

(2) the registered or certified mail receipts; and

(3) a map showing the property boundaries, surface owner names, and parcel numbers of all notified parties.

(f) Notice by publication. In addition to the notice required by subsection (d) of this section, an applicant for a stationary commercial fluid recycling facility permit shall also provide notice by publication.

(g) Newspaper of general circulation. The permit applicant shall publish notice of the application in a newspaper of general circulation in the county in which the proposed facility will be located at least once each week for two consecutive weeks, with the first publication occurring not earlier than the date staff determines that an application is complete pursuant to §1.201(b) of this title (relating to Time Periods for Processing Applications and Issuing Permits Administratively) but before the final review is completed.

(h) Contents of published notice. The published notice shall:

(1) be entitled "Notice of Application for Commercial Fluid Recycling Facility" if the proposed facility is a commercial facility;

(2) provide the date the applicant filed the application with the Commission;

(3) identify the name of the applicant;

(4) provide the location of the tract on which the proposed facility will be located including the legal description of the property, latitude/longitude coordinates of the proposed facility, county, name of the original survey and abstract number, and location and distance in relation to the nearest municipality or community;

(5) identify the owner or owners of the property on which the proposed facility will be located;

(6) identify the type of fluid waste to be managed at the facility;

(7) identify the proposed recycling method;

(8) state that affected persons may protest the application by filing a protest with the Commission within 30 calendar days of the last date of publication;

(9) include the definition of "affected person" pursuant to §4.110 of this title (relating to Definitions); and

(10) provide the address to which protests shall be mailed. If the Commission implements an electronic means for filing protests, then the location to instructions for electronic submittal shall be included.

(i) Proof of notice. The applicant shall submit to the Commission proof that notice was published as required by this section. Proof of publication shall consist of:

(1) an affidavit from the newspaper publisher that states the dates on which the notice was published and the county or counties in which the newspaper is of general circulation; and

(2) the tear sheets for each published notice.

(j) Protest process. Any statement of protest to an application must be filed with the Commission within 30 calendar days from the date notice is completed or from the last date of publication if notice by publication is authorized by the Director.

(1) The Technical Permitting Section shall notify the applicant if the Commission receives an affected person's timely protest. A timely protest is a written protest date-stamped as received by the Commission within 30 calendar days of the date notice is completed or within 30 calendar days of the last date of publication, whichever is later.

(2) The applicant shall have 30 days from the date of the Technical Permitting Section's notice of receipt of protest to respond, in writing, by either requesting a hearing or withdrawing the application. If the applicant fails to timely file a written response, the Technical Permitting Section shall consider the application to have been withdrawn.

(3) The Technical Permitting Section shall refer all protested applications to the Hearings Division if a timely protest is received and the applicant requests a hearing.

(4) The Commission shall provide notice of any hearing convened under this subsection to all affected persons and persons who have requested notice of the hearing.

(5) If the Director has reason to believe that a person entitled to notice of an application has not received notice as required by this section, then the Technical Permitting Section shall not take action on the application until notice is provided to such person.

(6) The Commission may issue a permit if no timely protests from affected persons are received.

(k) Director review. If the Director has reason to believe that a person to whom the applicant was required to give notice of an application has not received such notice, then the Director shall not take action on the application until the applicant has made reasonable efforts to give such person notice of the application and an opportunity to file a protest to the application with the Commission.

§4.288. Minimum Permit Provisions for Siting.

(a) A permit for a stationary commercial fluid recycling facility may be issued only if the Director or the Commission determines that the facility is to be located in an area where there is no unreasonable risk of pollution or threat to public health or safety.

(b) A stationary commercial fluid recycling facility permitted pursuant to this division is prohibited within a 100-year flood plain.

(c) Factors that the Commission will consider in assessing potential risk from a stationary commercial fluid recycling facility include:

(1) the volume and characteristics of the oil and gas waste, partially treated waste and recyclable product to be stored, handled, treated and recycled at the facility;

(2) distance to any surface water body, wet or dry;

(3) depth to and quality of the shallowest groundwater;

(4) distance to the nearest property line or public road;

(5) proximity to coastal natural resources, sensitive areas as defined by §4.110 of this title (relating to Definitions), or water supplies, and/or public, domestic, or irrigation water wells; and

(6) any other factors the Commission deems reasonably necessary in determining whether or not issuance of the permit will pose an unreasonable risk.

(d) All siting requirements in this section refer to conditions at the time the facility is constructed.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Railroad Commission of Texas
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DIVISION 7. BENEFICIAL USE OF DRILL CUTTINGS

16 TAC §4.301, §4.302

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §81.0531, which gives the Commission authority to assess penalties for violations of provisions of Title 3, Texas Natural Resources Code, which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under that title; Texas Natural Resources Code §§85.042, 85.202, and 86.042, which require the Commission to adopt rules to prevent waste of oil and gas; Texas Natural Resources Code §91.101, which gives the Commission authority to adopt and enforce rules and orders and issue permits to prevent pollution of surface water or subsurface water in the state; Texas Natural Resources Code §91.1017 (added by House Bill 2201, 87th Legislature), which requires the Commission to establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities; Texas Natural Resources Code §122.004 (amended by House Bill 3516, 87th Legislature), which requires the Commission to adopt rules to govern the treatment and beneficial use of oil and gas waste, which shall encourage fluid oil and gas waste recycling for beneficial purposes and to establish standards for the issuance of permits for commercial recycling of oil and gas waste; and Texas Natural Resources Code §123.0015 (added by Senate Bill 1541, 85th Legislature), which requires the Commission to define "legitimate commercial product" and adopt criteria for beneficial uses of recycled drill cuttings; and Texas Water Code Chapter 29, which gives the Commission authority to adopt rules, issue permits, and assess penalties related to transporters of oil and gas waste.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, 81.0351, 85.042, 85.202, 86.042; Texas Natural Resources Code §91.101 and §91.1017; Texas Natural Resources Code §122.004; Texas Natural Resources Code §123.0015; and Texas Water Code Chapter 29.

Cross reference to statute: Texas Natural Resources Code, Chapters 81, 85, 86, 91, 122, and 123; and Texas Water Code Chapter 29.

§4.301. Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings.

(a) The Commission encourages recycling of oil and gas waste. In addition to the requirements of Divisions 3 and 4 of this subchapter (relating to Requirements for Off-Lease or Centralized Commercial Solid Oil and Gas Waste Recycling, and Requirements for Stationary Commercial Solid Oil and Gas Waste Recycling Facilities, respectively), operators performing activities permitted under those divisions shall comply with the requirements of this division for activities related to the treatment and recycling for beneficial use of drill cuttings.

(b) The Commission may approve a permit for the treatment and recycling for beneficial use of drill cuttings if the treated drill cuttings are used:

(1) in a legitimate commercial product for the construction of oil and gas lease pads or oil and gas lease roads;

(2) in another type of legitimate commercial product if the applicant can demonstrate that the product:

(A) meets the engineering requirements for the proposed use as determined by a professional engineer licensed in Texas;

(B) is at least as protective of public health, public safety, and the environment as the use of an equivalent product made without treated drill cuttings; and

(C) does not cause or contribute to the pollution of surface or subsurface water.

(c) The application shall provide any other information requested by the Commission to determine the legitimacy and safety of an application.

§4.302. Additional Permit Requirements for Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings.

(a) An applicant for a permit to treat and recycle drill cuttings for beneficial use shall show that there is a demonstrated commercial market for the treated drill cuttings. The applicant may make this showing by providing:

(1) evidence that the same product made with drill cuttings or a product that is substantially similar is commonly used in the area where the product is created;

(2) evidence of actual commitments from customers who intend to use the product made with drill cuttings, including information regarding the volume of product the customers intend to use annually; or

(3) other credible and verifiable means consistent with the rules in this chapter.

(b) An applicant for a permit to treat and recycle drill cuttings for beneficial use shall perform a trial run in accordance with the following procedure.

(1) The applicant shall notify the Commission District Office for the county in which the facility is located prior to commencement of the trial run.

(2) The applicant shall demonstrate the ability to successfully process a 1,000 cubic yard batch of drill cuttings before the facility receives or processes any additional drill cuttings.

(3) The applicant shall collect samples of the treated drill cuttings from every 200 cubic yards of the first 1,000 cubic yard batch.

(4) Samples collected shall be analyzed and shall not exceed the parameters specified in Figure 1 or Figure 2 in subsection (c) of this section, as applicable.

(5) A written report of the results from the trial run prepared by a professional engineer licensed in Texas shall be submitted to the District Office and the Technical Permitting Section within 60 days of receipt of the analytical requirement in §4.258 of this title (relating to Minimum Permit Provisions for Operations). The report shall include:

(A) a summary of the trial run and description of the process;

(B) the actual volume of drill cuttings processed;

(C) the type of waste and description of the waste material;

(D) the volume and type of each stabilization material used; and

(E) copies of all chemical and geotechnical laboratory analytical reports and chain of custody sheets for the samples required in paragraph (3) of this subsection, as applicable.

(6) The applicant shall notify the District Office for the county in which the facility is located and the Technical Permitting Section at least 72 hours before processing begins. No additional drill cuttings shall be received or processed while the results of the trial run are being reviewed by the Technical Permitting Section. Any legitimate commercial product produced during the trial run shall not be used until the Technical Permitting Section has received the trial run reports

and provides written confirmation that the trial run requirements have been met.

(c) In addition to the permit standards under this subchapter, beneficial uses for treated and recycled drill cuttings shall meet the following criteria.

(1) For use of treated and recycled drill cuttings in a legitimate commercial product for the construction of oil and gas lease pads and oil and gas lease roads, the following requirements shall apply.

(A) Bench scale tests shall be performed as needed to determine optimum mixing composition. If the composition mixture changes from the treated drill cuttings produced during the trial run, the treated drill cuttings shall be analyzed for wetting and drying durability by ASTM 559-96, modified to provide samples that are compacted and molded from finished treated drill cuttings. Total weight loss after 12 cycles shall not exceed 15%.

(B) A sample of the treated drill cuttings shall be tested for the parameters listed in Figure 1 in this subsection for the trial run required by subsection (b) of this section and for every 800 cubic yard batch of treated drill cuttings produced thereafter. Each 800 cubic yard sample shall be composed of a composite of four sub-samples obtained at 200 cubic yard intervals. Each sample shall have a complete chain of custody and shall be analyzed for the parameters on Figure 1 in this subsection.

(C) Any treated drill cuttings not meeting the limitations specified in Figure 1 in this subsection shall be returned to the mixing cycle, reprocessed, and reanalyzed until the drill cuttings meet the required parameters or shall be disposed of in accordance with Commission rules.
Figure: 16 TAC §4.302(c)(1)(C)

(2) The Commission may require that use of treated drill cuttings in legitimate commercial products other than those described in paragraph (1) of this subsection comply with criteria in addition to those specified in this section.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 6. GEOTHERMAL RESOURCES
SUBCHAPTER A. SHALLOW CLOSED-LOOP GEOTHERMAL SYSTEMS

16 TAC §§6.101 - 6.106, 6.108 - 6.112

The Railroad Commission of Texas (Commission) adopts new Chapter 6, relating to Geothermal Resources. Specifically, the Commission adopts Subchapter A of Chapter 6, relating to Shallow Closed-Loop Geothermal Systems, which includes new §§6.101 - 6.106, and 6.108 - 6.112, relating to Purpose and Scope; Definitions; Applicability and Compliance; Authorization by Rule; Authorization for a Shallow Closed-Loop Geothermal System; Construction Standards; Pump Installer Requirements; Operational Standards; Well Reports; Plugging; and Enforcement and Penalties, respectively. Section 6.108 and §6.112 are adopted without changes and §§6.101 - 6.106, and 6.109 - 6.111 are adopted with changes to the proposed text as published in the October 11, 2024, issue of the *Texas Register* (49 TexReg 8261). Section 6.107, relating to Leak Detection and Pressure Loss, is withdrawn. The text of the rules adopted without changes from the proposal will not be republished.

The new rules implement the requirements of Senate Bill 786 (88th Legislature, Regular Session, 2023). Senate Bill 786 amended Texas Water Code §27.037 to transfer regulatory authority of closed-loop geothermal injection wells to the Commission from the Texas Commission on Environmental Quality (TCEQ). Thus, the bill provided the Commission with jurisdiction and permitting authority for these wells. The TCEQ retains jurisdiction over ground-source air conditioning return flow wells, which are shallow open-loop geothermal injection wells. All other types of geothermal injection wells are now under the jurisdiction of the Commission.

Transferring regulatory authority for shallow closed-loop geothermal injection wells to the Commission will lessen the administrative burden for those who seek to drill and operate shallow closed-loop geothermal injection wells because it consolidates authority in fewer agencies. The new rules retain the general process required for drilling and operating these types of wells. Some updates to the former process are adopted to provide flexibility for changes in innovation and technology.

The Commission received comments from 17 commenters, three of which were associations (Texas Groundwater Association ("TGWA"), Sierra Club, Lone Star Chapter ("Sierra Club"), and Texas Geothermal Energy Thermal Alliance ("TxGEA")), and 14 of which were individuals. Two individuals provided general statements that they agree with all comments and proposed amendments provided by TGWA. The Commission notes that any subsequent reference to comments made by TGWA are to be construed to include the support of these two individuals. A group of 12 other individuals provided separate copies of the same comments, and thus will be subsequently referred to as "the 12 individuals." The Commission greatly appreciates the comments provided by all individuals and associations.

TxGEA commented that it has reviewed the proposed rules and supports them without any recommended amendments. The Commission appreciates TxGEA's comments and continued support of this rulemaking.

TGWA made general comments suggesting that the Commission develop a "best practice guideline," or similar document, using ANSI CSA, IGHSA C448 as a reference. The Commission will consider developing guidelines to assist industry in complying with these rules. The Commission also understands that there is an existing memorandum of understanding between TCEQ, Texas Department of Licensing and Regulation (TDLR), and groundwater conservation districts, and the Commission will coordinate with the entities to create a new memorandum of understanding that is consistent with these rules to provide additional clarity.

Throughout proposed rules, the 12 individuals suggest replacing the word "system" with "injection well." The individuals specifically identified "systems" proposed at §§6.101, 6.102(9), 6.102(15), 6.104(a), 6.104(b), 6.105(a)(1), 6.105(a)(3), 6.105(c), 6.106(d)(3), and 6.111(b). They noted that "systems" are not currently regulated by TCEQ or TDLR, and therefore suggest the proposed term be removed.

The Commission disagrees that this recommended amendment is necessary to clarify the purpose and scope of the rules. While "system" is not used in the statute, the statute provides sufficient flexibility to use this term. The term also enables the Commission to describe all parts of shallow closed-loop geothermal systems, including the injection well and connections from the heat pump to the loop. In addition, although the statute uses "injection well," the United States Environmental Protection Agency (EPA) does not consider shallow ground source heat pump systems as injection wells under the Safe Drinking Water Act ("SDWA"). Thus, using "system" may prevent conflict with federal requirements.

Similarly, TGWA suggests replacing "geothermal" with "ground source heat pump" throughout the proposed rules to better describe the process occurring in shallow closed-loop geothermal systems. In the alternative, they suggested replacing "geothermal" with "geothermal heat injection well." TGWA makes this suggestion to mirror established industry nomenclature ("ground source heat pump borehole") and thus eliminate any confusion. However, TGWA acknowledged that the legislature defined "Shallow Closed-Loop Geothermal Injection Well" through SB 786, and thus the Commission may be limited in its ability to make changes. They encourage the Commission to continue communicating with the legislature to improve definitions to mirror established industry nomenclature, such as "ground source heat pump borehole." The 12 individuals suggested the same change, requesting that "geothermal injection well" be replaced with "ground source heat pump borehole."

The Commission disagrees with this specific change but agrees that the definition for shallow closed-loop geothermal systems proposed at §6.102(15) should be updated to better reflect the process occurring within the system. The heat pump is an integral part of the system and although the Commission is not regulating the heat pump itself, the Commission does regulate the connections between the heat pump and the heat exchange loop. As such, §6.102(20) is adopted with a change to incorporate the term "heat pump" and "heat transfer fluids." The revised definition will also clarify that the Commission considers its term "shallow closed-loop geothermal system" to be the same as a ground source heat pump system. The Commission also adopts §6.101 with a corresponding change to relate the scope and purpose of the rules to operations regulated, which include the drilling of the borehole, completion of the well, and the construction, operation, and plugging of shallow closed-loop geothermal systems. Additionally, the Commission removes the reference to "underground sources of drinking water" from §6.101, as this is a defined term within the SDWA, and its usage is inconsistent with current TCEQ rules. The Commission amends §6.101 accordingly.

Sierra Club commented that the Commission should establish a formal permitting process, as opposed to a registration process, so nearby landowners and other stakeholders are involved in the permitting process and have an opportunity provide comments or challenge the registration.

The Commission appreciates Sierra Club's comments but declines to amend the permitting process at this time. It is the Commission's understanding that the intent of SB 786 is to transfer regulation of shallow-closed loop geothermal systems to the Commission from TCEQ without material changes to the process. The Commission also notes that these systems are relatively small and pose little environmental risk. Additionally, as discussed in more detail below, the Commission will adopt §§6.104(c)(1) and 6.106(e) with changes based on the comments to clarify that individual permitting is required for any system that deviates from the construction and operational standards in §6.106 and §6.109, including using heat transfer fluids and antifreeze additives other than potable water, food grade propylene glycol, or USP-grade propylene glycol. The changes to §6.104 discussed later in the preamble will further mitigate environmental risks. Given the low environmental risk, the Commission likens these wells to water wells, which do not require owners to notify adjacent landowners. Risk is further alleviated by revisions relating to siting requirements. In response to comments further detailed below, the Commission will adopt the language proposed in §6.109(d) with changes to require wells be located at least ten feet from adjacent property lines and sewer lines, rather than potable water sources, and move it to adopted §6.106(a). The Commission believes these two changes achieve the goal of lowering risk to adjacent property owners and other stakeholders, as well as avoid unnecessarily complicating the permitting process.

Regarding notification and participation of other stakeholders, groundwater conservation districts, TDLR, and TCEQ coordinate their actions under the existing memorandum of understanding in 16 Texas Administrative Code §76.111, relating to Memorandum of Understanding between the Texas Department of Licensing and Regulation and the Texas Commission on Environmental Quality. As previously stated, the Commission will work with these entities to create a new memorandum of understanding, which will provide an opportunity for these stakeholders to voice concerns about the process through which these systems are authorized.

Sierra Club recommended the rules be amended to include requiring applicants of shallow closed-loop geothermal systems to: (1) pay an appropriate fee ($250 for registration, $1,000 for individual permit) to support the review of registrations and the application process; (2) require companies to have a bond, letter of credit, or other financial assurance at 50% of the expected cost to plug the well; (3) provide notice to adjacent landowners, and all landowners within one mile of the proposed well, allow for public comment and input, including an option to request the applicant file an individual permit or otherwise contest the registration; and, (4) provide notice to the groundwater conservation district, if the proposed well is located within the district's boundaries.

The Commission declines to adopt these recommendations. Regarding requiring applicants to pay a fee, the Commission lacks the statutory authority to collect registration fees from applicants, and as previously stated, it is the Commission's understanding that the legislature's intent was to transfer the program from TCEQ to the Commission without significant changes. Regarding financial assurance, it is the Commission's understanding that the vast majority of closed-loop geothermal systems in Texas use potable water as a heat transfer fluid; however, with the aforementioned changes to §6.106(e), the Commission will require individual permits for any system that uses a heat transfer fluid other than potable water, food grade propylene glycol, or USP-grade propylene glycol. As such, the Commission will analyze if any additional permit conditions are appropriate on a case-by-case basis specific to an applicant's deviation from the standards outlined in §6.106 and §6.109. Regarding adjacent and nearby landowner notice and opportunity to comment on or contest a registration, the Commission respectfully declines to adopt these changes based on the low risk of the systems and changes in siting requirements discussed previously. Regarding notice requirements to groundwater conservation districts, the new memorandum of understanding will provide an opportunity for stakeholders to express any concerns about lack of notification or participation.

Both the 12 individuals and TGWA made several comments regarding amending the definitions within §6.102, including the addition of several new definitions. The Commission appreciates all recommendations.

The 12 individuals noted that there is some confusion surrounding proposed §6.102(5), adopted as §6.102(10), the definition for "Individual Permit." They noted that it is also referred to as a "Request for Authorization," and requested clarification that no standalone fee is required.

The Commission understands the benefit of additional clarification regarding these terms. First, the Commission notes that the new rules do not require fees for either a Request for Authorization, or for an Individual Permit. A Request for Authorization and an Individual Permit are not the same -- an Individual Permit requirement may be triggered if the applicant's Request for Authorization or well report meet the criteria in §6.104(c)(1). A Request for Authorization is the method through which an applicant registers a shallow closed-loop geothermal system that will be authorized by rule if the Director finds that the system complies with all requirements of the rules. The Commission notes that §§6.104 and 6.105 are adopted with changes to clarify the difference between an individual permit and a request for authorization, which is revised upon adoption to be called "a registration of a shallow closed-loop geothermal system for authorization by rule."

The 12 individuals and TGWA suggested adding definitions for "annular space," "aquifer," "casing," "grouting," and "heat exchange loop." The Commission agrees and adopts §6.102 with changes to incorporate the suggested terms and definitions with a few minor changes.

The 12 individuals and TGWA provided additional language in their proposed definition of "grouting" specifying appropriate grouting materials, as well as grouting alternatives. TGWA's comment differed slightly by referring to grouting alternatives as "alternative backfill," and making it a separate definition.

The Commission declines to include this language in the definitions in §6.102 but will include the suggested language concerning grouting in §6.106(d)(2). The Commission will also include a portion of the commenters' recommended language for grouting alternatives in §6.106(d)(2) as well.

Additionally, for the definition of "Heat Exchange Loop," the 12 individuals and TGWA recommended specifying that high-density polyethylene pipe (HDPE) is required. The Commission declines to mandate a specific type of piping and instead will use "polyethylene pipe" to allow flexibility. The Commission notes that §6.106(d)(7) requires polyethylene piping to meet applicable American Society for Testing and Materials ("ASTM") standards.

Regarding proposed §6.102(7), adopted as §6.107(12), the 12 individuals commented that the language referring to a "pump installer" should be removed, as all pumping is performed from the surface and does not currently require a pump installer's license.

The Commission disagrees with this change. The Commission confirmed with TDLR that a license is not required when the pump is installed above ground, as most shallow closed-loop heat systems are designed. However, the Commission notes that a pump installer's license is required for submersible pumps, which may be installed. In addition, even when a licensed pump installer is not required, the system still requires an individual to install the pump. The Commission uses the term "pump installer" to refer to the individual who installs the pump, even when a license is not required. Therefore, Commission finds the definition is still relevant.

Similarly, both the 12 individuals and TGWA recommended entirely removing definitions proposed in §6.102(11)-(13), which include the terms "pitless adapter," "point of injection," and "pump installer." The Commission agrees with removing point of injection but disagrees with removing the definitions for pitless adapter and pump installer. As mentioned above, the Commission recognizes that the majority of shallow closed-loop geothermal systems utilize a surface pump, and thus a pitless adapter and pump installer's license is unnecessary. However, the Commission declines to remove these definitions in case a submersible pump is used in the system, making the terms "pitless adapter" and "licensed pump installer" relevant. The Commission adopts §6.102 with changes to update the definition of pump installer and to add a definition for "licensed pump installer" for clarity.

The 12 individuals and TGWA recommended changing proposed §6.102(14) to define a shallow closed-loop geothermal injection well based on total well depth between 200 and 1000 feet, removing the language relating to total dissolved solids ("TDS"). Additionally, both commenters suggested rewriting "shallow closed-loop geothermal injection well" with "a heat injection borehole," or "a shallow closed-loop geothermal system."

The Commission disagrees with these revisions. The International Ground Source Heat Pump Association ("IGSHPA") defines shallow closed-loop geothermal injection wells based on TDS, not total well depth. Additionally, to maintain consistency with the statute, the Commission declines to change "shallow closed-loop geothermal injection well" to either option proposed by the individuals or TGWA.

The Sierra Club made one general comment about §6.103, expressing support for the clarification that the subchapter does not apply to open-loop air conditioning return flow wells that remain under the jurisdiction of TCEQ. Sierra Club also stated that it appreciates the distinction stating this subchapter only applies to shallow closed-loop geothermal systems used on site, not larger systems meant to generate energy for sale or transfer to energy markets. The Commission appreciates Sierra Club's comments and support.

For §6.103(a), the 12 individuals suggested expanding the scope of the subchapter to apply to systems designed or contracted for prior to January 6, 2025. They noted that this change could remedy excessive requests for authorization.

The Commission disagrees. The suggested revisions could confuse which systems these rules apply to, and the Commission would not have any information to verify dates of designs or contracts. As such, the Commission declines to adopt the requested change.

TGWA commented requesting language in §6.103(b) that would specifically exempt systems constructed prior to January 6, 2025. The suggested addition is: "Any shallow closed-loop geothermal systems in this state which were constructed before January 6, 2025 shall be grandfathered, unless altered, deteriorated, abandoned or determined by the Director to (1) encounter groundwater that is detrimental to human health and the environment or can cause pollution to land, surface water, or other groundwater; (2) cause a violation of primary drinking water regulations under 40 CFR Part 142; or (3) otherwise adversely affect human health or the environment."

Additionally, TGWA suggested adding horizontal geothermal heat pump systems, and pond/lake geothermal heat pump systems to the exceptions list under proposed §6.103(b), which is adopted as §6.103(c). The Commission supports the recommendation to exempt shallow closed-loop geothermal systems constructed prior to January 6, 2025, and adopts §6.103 with that change. The Commission also supports the addition of pond/lake geothermal heat pump systems, but not horizontal geothermal heat pump systems. As such, the Commission will add language exempting pond/lake geothermal heat pump systems only.

Under proposed §6.103(c), the 12 individuals suggest adding "licensing" in front of "requirements of TDLR regulations." The Commission agrees that this provides additional clarity to proposed subsection (c), adopted as subsection (d), and adopts this change accordingly.

The 12 individuals suggested adding introductory language to §6.104 stating that shallow closed-loop geothermal injection wells are allowable by rule, installing contractors must follow all state, local, and groundwater district rules, and that P-5 permitting is not required. They also sought to clarify that there is not a required standalone fee for registration, that a "request for authorization" is also referred to as an "individual permit," and suggested creating an "application for variance" that may be applied for through the Director.

The Commission declines to include any of the suggested language. Regarding P-5 Permitting, currently, applicants are required to have a P-5 under §91.142 of the Natural Resources Code, which requires operators conducting any activity under the Commission's jurisdiction to file a Form P-5. Regarding a standalone fee, the Commission has previously stated this is not required. The Commission agrees that additional clarity is needed in §6.104 and §6.105 regarding "request for authorization" and "individual permit," but declines to adopt the commenter's suggested amendments. The Commission has amended both sections to better describe the "authorization by rule" process and when an individual permit may be required. The Commission has added a new subsection (a) to §6.104 to better describe the operation of an "authorization by rule," which is a permit by rule process. All proposed subsections of §6.104 have been redesignated accordingly.

TWGA commented that proposed §6.104(b) needs additional clarity to accurately describe when §6.105 applies. They suggested including the language "In the event that a shallow closed-loop geothermal system will knowingly be out of compliance with this subchapter, the owner must submit to the Director a request for authorization, as required by §6.105 of this title."

The Commission agrees that additional clarity is needed but does not agree to add the specific language TWGA suggested. Sections 6.104(b) and 6.105 are connected as stated in proposed §6.104(b). The Commission notes that due to changes based on comments, proposed §6.104(b) is adopted as §6.104(c). These changes are discussed further in the following paragraphs.

Section 6.104 authorizes shallow closed-loop geothermal systems that comply with the requirements of the subchapter. The systems are authorized, and the system owner is not required to apply for and obtain an individual permit unless the Director finds that the system meets any of the conditions listed in proposed §6.104(b) (adopted §6.104(c)). Though the systems are eligible to be authorized by rule (i.e., permitted by rule) a registration and well report must be provided so the Commission can determine whether the system is consistent with the rules or if any other conditions listed in §6.104(c) are present. In proposed §6.104 and §6.105, the Commission called the registration the "request for authorization." To reduce confusion, the Commission revises that term and now refers to a "registration" in adopted §6.104 to mirror the changes in adopted §6.105, detailed below. To provide additional clarity regarding when an individual permit may be required, the Commission adds a condition in §6.104(c)(1)(C) denoting that deviation from any construction or operational standard described in the rules is cause for the Director to require an individual permit. For example, if a system utilizes any heat transfer fluid other than potable water and the approved additives listed in §6.106, an individual permit may be required. As previously stated, neither a registration of a shallow closed-loop geothermal system for authorization by rule nor an individual permit requires payment of a standalone fee at this time.

Section 6.105 specifies the process for registering the authorized system with the Commission. The registration is required even when the system is authorized under §6.104. As discussed in the preceding paragraph, the Commission will replace "request for authorization" with "registration" each time it appears in §6.104 and §6.105. Additionally, the Commission amends the title of §6.105 to "Registration of a Shallow Closed-Loop Geothermal System for Authorization by Rule" to clarify that authorization by rule still requires registration. This update keeps the language in both rules consistent to provide clarity regarding the purpose of each section.

Under §6.105(a), both the 12 individuals and TGWA recommended removing language referring to a pump installer in subsection (a)(1). TGWA also requested removing subsection (a)(3) in its entirety.

As discussed above, a licensed pump installer is still required for the installation of a submersible pump. Therefore, the Commission adopts a change in §6.105(a)(3) to clarify that the requirement only applies when a submersible pump is installed. Additionally, under §6.105(a)(2), TGWA suggested adding "heat" between geothermal and injection wells. As previously stated, the Commission declines to adopt this change to be consistent with the relevant statutes.

Regarding §6.105(b), the 12 individuals and TGWA suggested replacing "water quality section" with "comment section" in reference to the Well Report Form.

The Commission agrees to remove "water quality section," but does not agree to include "comment section." With this revision, the Commission is requiring that any additive, constituent, or fluids other than potable water be reported on the Well Report Form but does not specify where that information must be reported. Thus, the Commission is providing flexibility within the rules for changes to the structure of the Well Report form.

Sierra Club expressed support for all the provisions of §6.106, noting that if the standards of §6.106 are followed, it will assure that these systems do not provide pathways for pollution or fluid migration. Sierra Club also specifically noted its support for the penalty language. The Commission appreciates Sierra Club's comment and support of §6.106.

The 12 individuals and TGWA suggested several revisions to §6.106. Regarding proposed subsection (a), both commenters suggested removing the entire subsection, stating that the completion of shallow closed-loop geothermal heat injection wells is below the surface and not meant to be accessed upon completion.

The Commission disagrees. The requirements of proposed subsection (a) are necessary to ensure that all piping is protected, and that water drains away from the well.

The 12 individuals and TGWA made several suggestions to proposed §6.106(b). Regarding proposed subsections (b)(1) and (b)(2), they suggested replacing "impervious bentonite" with "grouting." Additionally, both suggested replacing "sand, gravel, or drill cuttings" in proposed subsection (b)(2) with "alternative grouting."

The Commission generally agrees with these comments but declines to adopt the suggested language concerning grouting alternatives in full. As stated in response to comments on the definitions proposed in §6.102, the Commission will define grouting in accordance with the commenters' recommendations in §6.106(b)(1), adopted as subsection (d)(2), instead of in the definitions section. The Commission will include "solid bentonite chip," as an approved grouting alternative, and require all other materials to be approved by the Director. This is in accordance with IGSHPA standards and ensures that only materials which meet or exceed good engineering practices to create an impervious seal are used as grouting and grouting alternatives. The amendments state approved grouting materials consist of a combination of bentonite, cement, thermally enhanced material, or a combination of such materials. In instances where boreholes will not support a grouting slurry, grouting alternatives, such as solid bentonite chip material may be used. Proposed subsection (b)(2), adopted as subsection (d)(3), requires that where no groundwater or only one zone of groundwater is encountered during drilling, alternative grouting may be used to backfill up to 30 feet from the surface. The water well driller shall fill the top 30 feet of the annular space with grouting, or alternative grouting that has been approved by the Director.

The 12 individuals and TGWA also suggested amending proposed §6.106(b)(4), adopted as subsection (d)(5), to include a requirement that the borehole be no smaller than 4 inches, and large enough to freely install the loop, tremie line and grouting material.

The Commission declines to include this amendment because the proposed language is identical to international standards published by IGSHPA.

For proposed §6.106(b)(5) and (6), both the 12 individuals and TGWA suggested replacing "tubing" with "heat exchange loop," as defined by §6.102. Additionally, they recommended including a reference to ASTM D3035, which they noted is the appropriate standard of HDPE tubing in §6.106(b)(6). Similarly, under §6.106(b)(8), the 12 individuals suggested replacing "plastic loop" with HDPE tubing, and asked that alternate backfill sand materials be allowed with approval by the Director. TGWA recommended deleting paragraph (8) in its entirety.

The Commission agrees to replace "tubing" with "heat exchange loop" under proposed §6.105(b)(5) and (6), adopted as subsection (d)(6) and (7), but declines to include a reference to HDPE and ASTM D3035. The Commission also disagrees with deleting proposed paragraph (8) in its entirety or amending it to reference HDPE. As stated in response to comments regarding the definition of heat exchange loop under §6.102, the Commission chooses to retain flexibility for operators to use polyethylene piping material in accordance with ASTM standards, and thus declines to specify the type of polyethylene piping required.

Regarding proposed §6.106(b)(7), the 12 individuals and TGWA suggested the Commission include a requirement that any fused joints intended to be placed in the borehole are required to be constructed at the loop manufacturer facility. They also recommended deleting the last sentence referencing electrofusion joints and non-metallic mechanical stab type insert fittings, noting that they are not allowed by design teams or trade organizations to be used in a borehole. The Commission declines to adopt these two changes and will keep the proposed language as written. Similar to other portions of the rules, the Commission seeks to allow flexibility under proposed §6.106(b)(7), adopted as subsection (d)(8).

For proposed §6.106(b)(9) and (10), which discuss copper piping, the 12 individuals and TGWA recommended removing both subsections. They commented that copper piping is not typically used in Texas, is susceptible to corrosion, and should require an individual permit.

The Commission does not agree to remove proposed subsection (b)(9), adopted as subsection (d)(10), because even though copper piping may not be common, if it is used, copper piping should meet certain standards. Further, proposed subsection (b)(9), now subsection (d)(10), contemplates that other piping may be used. It states, "If copper tubing is used for heat exchange applications, all below grade copper connections shall be joined by brazing using a filler material with a high melting temperature such as a material with 15% silver content or equivalent." The Commission agrees to remove proposed subsection (b)(10), based on the comments stating that most systems utilize PE piping. The Commission adopts §6.106 with those changes.

The 12 individuals and TGWA suggested wholesale changes to proposed §6.106(c), including deleting paragraphs (1)-(3), removing "into bedrock" from paragraph (4), and editing paragraph (5) to state that temporary casing may be installed, not that it must be installed.

The Commission agrees to revise proposed §6.106(c), which is adopted as §6.106(d), but does not agree to remove all of paragraphs (1) - (3). Additionally, because casing is part of completion and drilling requirements, the requirements of proposed subsection (c) will be contained within subsection (d) "drilling and completion requirements," which was proposed as subsection (c). Casing requirements are renumbered as paragraph (1) under drilling and completion requirements. To provide clarity that casing is not required for all shallow closed-loop geothermal systems but may be necessary to ensure borehole integrity, the Commission will move the language in proposed subsection (c)(5) to adopted §6.106(d)(1). The casing requirements proposed in subsection (c)(1)-(3) will be adopted in §6.106(d)(1)(A)-(C) and will apply if temporary casing is used.

The 12 individuals and TGWA also recommended significant revisions to proposed §6.106(d), which is adopted as §6.106(e). First, they recommended retitling the subsection to "Heat Transfer Fluids," instead of just "Fluids." The Commission agrees with this recommendation and adopts the subsection with the requested change.

Additionally, both commenters suggested adding potable water and food grade propylene glycol to the list of approved heat transfer fluids, and suggested the Commission remove ethanol. If ethanol is removed from the list of approved heat transfer fluids, both the 12 individuals and TGWA stated that subsections (2) and (3) can be deleted.

The Commission agrees with adding potable water, and food grade propylene glycol, removing ethanol, and deleting subsections (2) and (3). The Commission will also include USP-grade propylene glycol in the list of approved heat transfer fluids.

The 12 individuals and TGWA also suggested including language that would allow alternative fluids to be used after approval from the Director. The Commission declines to include this statement. Any deviation from the approved heat transfer fluids would require an individual permit. If changes in technology occur and it becomes necessary to incorporate additional fluid types, the Commission can consider rule revisions at that time.

Additionally, the Commission moves some provisions from §6.109 to §6.106 for clarity, including the standards for siting and setback, and prohibiting commingling. Both of these standards were proposed under §6.109, Operational Standards, but are best described as Construction Standards. The Commission has reorganized the subsections of §6.106 and §6.109 to reflect these changes. Comments regarding siting and setback, and commingling are addressed later in the paragraphs containing the Commission's responses to proposed §6.109.

The 12 individuals and TGWA both suggested deleting all of §6.107 due to the updates they provided for proposed §6.106(d), adopted as §6.106(e), relating to heat transfer fluids. They commented that if §6.106 is updated to only include non-toxic, non-hazardous, food grade heat transfer fluids, then §6.107 becomes unnecessary.

The Commission agrees §6.107 can be removed, as §6.106(e) has been amended to only include potable water, food grade propylene glycol, or USP-grade propylene glycol as approved heat transfer fluids. As such, the approved heat transfer fluids are non-toxic, non-hazardous, food-grade fluids. Any deviation from non-toxic, non-hazardous, food-grade heat transfer fluids would require the applicant to obtain an individual permit. The requirements proposed in §6.107 could be added to an individual permit if necessary, but are not needed when non-toxic, non-hazardous, food-grade heat transfer fluids are used. Section 6.107 will be withdrawn and not adopted.

The 12 individuals and TGWA suggested deleting §6.108 in its entirety due to its references to pump installers.

The Commission disagrees. As previously stated, the Commission adopts the rules with changes to clarify that a pump installer and a licensed pump installer are different. A pump installer is simply the person who installs a pump. For above-ground pumps, this person is not required to be a TDLR licensed pump installer. A licensed pump installer is required to install the pump when the system utilizes a submersible pump. Thus, the Commission will not remove §6.108, as it is not specific to a "licensed pump installer."

The 12 individuals recommended deleting §6.109(a)(1)-(3). They stated that since no part of the shallow closed-loop geothermal injection well is accessible or visible from the surface on the exterior of a building or residence, displaying the information required under paragraphs (1)-(3) would be overly burdensome and restrict the owner from protections provided by Texas Occupations Code §1901.251. The commenters also stated that proposed subsection (a)(2) could limit an owner's ability to hire a service or maintenance provider that is not listed on the system.

The Commission understands these concerns. Rather than deleting this section, the Commission adopts it with a change to merely require signage that identifies the geothermal system. The Commission agrees that the requirement to include the name and number of a person to contact in case of a shutdown or for routine maintenance could lead to confusion.

The 12 individuals and TGWA suggested adding "air" to §6.109(b) as a viable option for pressure testing.

The Commission disagrees. These systems shall be tested with matter in the same state intended to be used in operation. As such, only water may be used for pressure tests.

The 12 individuals recommended removing §6.109(c). They stated that because there is no physical injection or extraction occurring through the borehole, sampling is unnecessary.

The Commission agrees and adopts §6.109 with the requested revision. If a system uses a heat transfer fluid other than water, food-grade or USP-grade propylene glycol, the Commission may include sampling requirements in an individual permit.

The 12 individuals and TGWA recommended removing and replacing "potable water sources" with "adjacent property lines" in proposed §6.109(d), adopted as subsection (c).

The Commission agrees to this amendment. As stated in the comments, this change is consistent with 16 Texas Administrative Code, Chapter 76. This subsection is moved and adopted under §6.106(a), as discussed above.

Regarding proposed §6.109(e), the 12 individuals and TGWA recommended removing "through the casing annulus or the gravel pack."

The Commission agrees because the remaining language is sufficient to address the Commission's concerns regarding commingling. This subsection is moved and adopted under §6.106(c), as noted above. Adopted §6.109 is renumbered to reflect the movement of these two subsections to §6.106.

Regarding §6.110, the 12 individuals and TGWA stated that it was their understanding that a well report was not needed for each well when multiple boreholes are drilled as part of the same system. They suggested that to avoid confusion, a map or schematic should be required. Both TGWA and the 12 individuals suggested edits to §6.110(a) to provide clarity regarding the need for one well report only.

The Commission agrees that a well report is not needed for each well. The Commission adopts §6.110 with the language TGWA provided, adding a final sentence to subsection (a) stating, a "well report is not needed for each well constructed on one site, however a map or drawing of each well must be provided." Additionally, the Commission adopts §6.110(b) with changes to the well report list to illustrate that multiple wells may be included under one well report. For example, "well or wells," and "owner of the well or wells," are used instead of "well" and "owner of the well."

To further provide clarity, the Commission will combine §6.110(b)(8)-(10) and state that a "schematic showing the borehole diameter in inches, the bottom depth in feet, and the drilling method" is required with the Well Report. The Commission adopts the remaining paragraphs with corrected paragraph numbers.

Additionally, regarding §6.110(b), the 12 individuals and TGWA suggested adding an additional subsection stating that any additives, constituents, or fluids used to make up the heat transfer fluid, must be on the well report. The Commission agrees and will add this requirement in adopted §6.110(b).

In §6.110(d), the 12 individuals and TGWA recommended removing the requirement for an owner to transfer a well, and instead treating a shallow closed-loop geothermal system more like a water well, which transfers with the property at the time of conveyance. The Commission agrees, and will include the language provided by TGWA, which states a "shallow closed-loop geothermal system, once drilled, installed, and operating, is a permeant fixture of the property. If the property is transferred, both the transferor owner and transferee owner shall notify the Commission of the transfer within 30 days of the date of the transfer."

The 12 individuals and TGWA suggested several edits to §6.111. Both parties suggested replacing subsection (a)(1) and (2) with language requiring the owner to engage in alternative plugging activities such as removing all heat transfer fluid from the closed loop system and taking necessary precautions to ensure groundwater protection; excavating to the top of the borehole and cutting off the heat exchange loop at least three feet below the surface; and filling the upper one foot of the borehole with grout and the remaining hole with compacted earth.

The Commission declines to adopt this language. The proposed language is consistent with the requirements in place prior to the legislature's transfer of authority from TCEQ to the Commission. The proposed language also allows for greater flexibility, while still maintaining appropriate plugging standards.

Regarding §6.111(c), the 12 individuals and TGWA suggested removing the requirement for a signed statement that the well was plugged in accordance with §6.111, and replacing it with a requirement that a driller or well owner who plugs an abandoned well shall submit to the Commission a completed copy of their well plugging report filed with the Texas Department of Licensing and Regulation electronically through the Texas Well Report Submission and Retrieval System. They noted that this will allow licensed drillers to fulfill the licensing requirements of the TDLR. The Commission agrees with this change and adopts §6.111(c) with changes to incorporate it.

That concludes the summary of comments received on the proposed new rules. The Commission appreciates the input provided by stakeholders. The remaining paragraphs summarize the requirements of the adopted rules.

As stated in §6.101, the new rules in Subchapter A of Chapter 6 specifically address shallow closed-loop geothermal injection wells, which are defined in §6.102 as injection wells that are part of shallow closed-loop geothermal systems. These types of wells are limited to a depth of formations that contain water with a total dissolved solids content of 1000 parts per million (ppm) or less. This parts per million standard ensures consistency with definitions developed by the Texas Groundwater Protection Committee. Section 6.101 is adopted with changes due to the comments.

Section 6.102 contains definitions for terms used throughout the subchapter such as fresh water, injection well, license number, pump installer, water well driller, and well report. Section 6.102 is adopted with changes due to the comments.

Section 6.103 clarifies that the subchapter only applies to shallow closed-loop geothermal systems for which construction is commenced after the effective date of Subchapter A. The section is adopted with changes due to comments but the proposed effective date of January 6, 2025, is unchanged.

Section 6.103 also clarifies types of shallow-closed loop geothermal systems to which the subchapter does not apply. Section 6.103 is adopted with changes due to the comments.

Section 6.104 specifies that a person in compliance with Subchapter A may cause a shallow closed-loop geothermal system to be drilled and installed and may operate the system without obtaining an individual permit. In other words, a shallow closed-loop geothermal system is authorized by rule (i.e., permitted by rule) provided it is drilled, installed, and operated in accordance with Subchapter A. Section 6.104 states this general rule and provides for exceptions based on the Director's review. Section 6.104 is adopted with changes due to the comments.

Section 6.105 describes the procedure for registering a shallow closed-loop geothermal system. The section is adopted with changes due to comments.

Section 6.106 contains the construction standards with which the licensed water well driller must comply when drilling a shallow closed-loop geothermal injection well. Subsection (a) contains the siting and setback requirements. Subsection (b) contains the surface completion requirements, including the requirement to place a concrete slab or sealing block above the cement slurry around the well. Subsection (b) also provides requirements for the concrete slab or sealing block. Subsection (c) prohibits commingling, requiring shallow closed-loop geothermal systems to be completed in a manner that prevents waters that differ significantly from mixing. Subsection (d) contains the drilling and completion requirements for the licensed water well driller. Requirements for grouting material are included but the water well driller is also authorized to request the Director's approval for using a grouting alternative that is similarly impervious if the borehole will not support a traditional grouting slurry.

Although casing is not required in every system, temporary casing may be required to ensure borehole integrity. Casing for shallow closed-loop geothermal injection wells is addressed in subsection (d) of §6.106, in paragraph (1). Subsection (e) of §6.106 outlines the fluids that may be used as antifreeze additives. Only potable water, food grade propylene glycol, and USP-grade propylene glycol may be used as antifreeze additives for a shallow closed-loop geothermal injection well. To use any other additive, the system requires an individual permit.

Section 6.108 contains the requirements for the individual that installs the pump on the shallow closed-loop geothermal system.

Standards for operating the shallow closed-loop geothermal system are adopted in §6.109. Requirements for safety, pressure testing, and conformance with local regulations are found in subsections (a), (b) and (c). Proposed subsection (c) is removed and the remaining subsections redesignated. Proposed subsection (d) and proposed subsection (e) are moved and adopted under §6.106 as subsections (a) and (c), respectively. Adopted §6.109 (c), proposed as subsection (f), notes that site plans may be required by local jurisdictions.

Section 6.110 contains the requirement for a licensed water well driller to submit an electronic copy of the report required by §76.70 of this title (relating to Responsibilities of the Licensee -- State Well Reports) to the Director within 30 days of well completion for each well drilled. This information is consistent with the information currently required on the report under §76.70. Section 6.109 also contains the requirements for transferring ownership of a shallow closed-loop geothermal injection well and specifies that the transferee owner shall be responsible for plugging the well upon abandonment. Section 6.110 is adopted with changes to specify that a shallow closed-loop geothermal system is a fixture on real property. As such, ownership of a shallow closed-loop geothermal injection well transfers with the property.

Section 6.111 outlines plugging requirements for shallow closed-loop geothermal injection wells upon permanent discontinued use or abandonment. Subsections (a) and (b) contain the technical requirements for plugging, and subsection (c) requires the person who plugs the well to submit to the Commission a completed copy of the well plugging report filed with the Texas Department of Licensing Regulation through the Texas Well Report Submission Retrieval System, not later than the 30th day after the well is plugged. The Commission will coordinate with TDLR, groundwater conservation districts, and Commission field offices to investigate complaints regarding abandoned and/or deteriorated shallow closed-loop geothermal injection wells.

Section 6.112 describes the process the Commission will follow to enforce violations of Subchapter A or the conditions of a permit issued under §6.104(b). Section 6.112 also contains penalties for violations.

The Commission adopts the new rules under Texas Water Code, §27.037, which gives the Commission jurisdiction over closed-loop geothermal injection wells and the authority to issue permits for closed-loop geothermal injection wells. Section 27.037 also requires the Commission to adopt rules necessary to administer the section and to regulate closed-loop geothermal injection wells.

Statutory authority: Texas Water Code, §27.037.

Cross-reference to statute: Texas Water Code, Chapter 27.

§6.101. Purpose and Scope.

This subchapter implements the state program for the regulation of shallow closed-loop geothermal systems under the jurisdiction of the Commission consistent with state and federal law for the protection of fresh water,, including regulation of the drilling of the borehole, completion of the well, and the construction, operation, and plugging of shallow closed-loop geothermal systems.

§6.102. Definitions.

The following terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Annular space--The space between the borehole wall and the heat exchange loop installed within the borehole.

(2) Aquifer--A geologic formation that contains enough saturated permeable material to provide significant quantities of water to wells and springs.

(3) Casing--A metal or plastic pipe installed into the borehole to prevent the sides from collapsing and to protect groundwater from contamination.

(4) Commission--The Railroad Commission of Texas.

(5) Director--The director of the Oil and Gas Division or the director's delegate.

(6) Fresh water--Groundwater containing 1000 parts per million (ppm) or less total dissolved solids.

(7) Groundwater conservation district--Any district or authority created under Section 52, Article III, or Section 59, Article XVI, Texas Constitution that has the authority to regulate the spacing of water wells, the production from water wells, or both as defined in Texas Water Code §36.001.

(8) Grouting--The material used to achieve an impervious seal in the borehole after the heat exchange loop has been installed.

(9) Heat exchange loop--A conduit used in shallow closed-loop geothermal heat systems factory manufactured by fusing a U-bend fitting to dual coil polyethylene pipe, with fusion equipment for heat transfer.

(10) Individual permit--A permit, other than an authorization by rule or general permit, for a specific activity at a specific location.

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

(12) License number--The number assigned to a water well driller or pump installer by the Texas Department of Licensing and Regulation (TDLR).

(13) Licensed pump installer--A person licensed by TDLR to install submersible pumps.

(14) Open-loop air conditioning return flow wells--Class V Underground Injection Control (UIC) wells used to return groundwater, which has been circulated through open-loop, heat pump/air condition (HAC) systems, to the subsurface. These wells are regulated by the Texas Commission on Environmental Quality under 30 Texas Administrative Code §331.11 and §331.12.

(15) Owner--The owner of a shallow closed-loop geothermal system subject to the requirements of this subchapter.

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

(17) Pitless adapter--An adapter that provides a water-tight connection between the drop pipe from the submersible pump inside a well and the water line running to the service location. The device not only prevents water from freezing but also permits easy maintenance of the system components without the need to dig around the well.

(18) Pump installer--A person who installs or repairs well pumps and equipment. A person does not have to be a "licensed pump installer" to install, repair, or service above ground pumps for shallow closed-loop geothermal systems.

(19) Shallow closed-loop geothermal injection well--An injection well that is part of a shallow closed-loop geothermal system. These types of wells are limited to a depth of formations that contain water with a total dissolved solids content of 1000 parts per million (ppm) or less.

(20) Shallow closed-loop geothermal system--A closed-loop geothermal injection well, including all heat pumps and tubing, heat transfer fluids, and connections from the injection well to the infrastructure and the geothermal heat exchange system, that operates as a heat source or heat sink in concert with a heating, ventilation, and air conditioning system designed to heat or cool infrastructure. These systems are also called "ground source heat pump systems."

All energy used from this type of system is consumed by the onsite infrastructure and is not provided to an energy market.

(21) TDLR--The Texas Department of Licensing and Regulation.

(22) Total dissolved solids--The total dissolved (filterable) solids as determined by use of the method specified in 40 Code of Federal Regulations Part 136.

(23) Tracking number--The designated number assigned by TDLR for a specific well report.

(24) Water well driller--A person or company possessing a water well driller's license issued by TDLR.

(25) Well report--The State of Texas Well Report administered by TDLR.

§6.103. Applicability and Compliance.

(a) This subchapter applies to shallow closed-loop geothermal systems in this state for which construction is commenced on or after January 6, 2025.

(b) Any shallow closed-loop geothermal system in this state which was constructed before January 6, 2025, is exempt from the requirements of this subchapter unless altered, deteriorated, abandoned, or determined by the Director to:

(1) encounter groundwater that is detrimental to human health and the environment or cause pollution to land, surface water, or other groundwater;

(2) cause a violation of primary drinking water regulations under 40 CFR Part 142; or

(3) otherwise adversely affect human health or the environment.

(c) This subchapter does not apply to:

(1) open-loop air-conditioning return flow wells used to return water that has been used for heating or cooling in a heat pump to the aquifer that supplied the water;

(2) other geothermal injection wells; or

(3) pond/lake geothermal heat pump systems.

(d) Compliance with this subchapter does not relieve the driller or installer from compliance with the licensing requirements of TDLR regulations adopted under Texas Occupations Code, Chapters 1901 and 1902.

§6.104. Authorization by Rule.

(a) An authorization by rule (or "permit by rule") provides authority to operate under predetermined requirements without a separate application process, so long as the Director confirms the activity meets the specified predetermined requirements.

(b) An owner in compliance with this subchapter is authorized by rule to cause to be drilled and installed and to operate a shallow closed-loop geothermal system and is not required to obtain an individual permit except as provided by subsection (b) of this section. The owner shall register the system as authorized by rule in accordance with §6.105 of this title (relating to Registration of a Shallow Closed-Loop Geothermal System for Authorization by Rule).

(c) The Director will review the registration required by §6.105 of this title (relating to Registration of a Shallow Closed-Loop Geothermal System for Authorization by Rule) and the well report required by §6.110 of this title (relating to Well Reports).

(1) The Director will review the registration and the well report to determine whether the shallow closed-loop geothermal injection well:

(A) encounters groundwater that is detrimental to human health and the environment or can cause pollution to land, surface water, or other groundwater;

(B) may cause a violation of primary drinking water regulations under 40 CFR Part 142;

(C) deviates from any construction or operational standards of §6.106 and §6.109; or

(D) may otherwise adversely affect human health or the environment.

(2) If upon review of the registration or the well report, or at any other time, the Director determines that a condition listed in paragraph (1) of this subsection exists, the Director may take any of the following actions:

(A) require the owner to obtain an individual permit;

(B) require the owner to take such actions (including, where required, closure of the injection well) as may be necessary to prevent the violation; or

(C) refer the violation for enforcement action.

(d) If the Director makes a determination under subsection (b) of this section, the owner shall cease injection operations until the owner complies with the Director's requirements. The owner may request a hearing to contest the Director's determination.

§6.105. Registration of a Shallow Closed-Loop Geothermal System for Authorization by Rule.

(a) Registration for authorization by rule.

(1) Prior to commencing operations for a shallow closed-loop geothermal system, the owner of the system shall submit to the Director a registration for authorization by rule. The registration shall be signed by the owner, include the TDLR license numbers required by paragraphs (2) and (3) of this subsection, and include the following statement: "I declare under penalties prescribed in Section 91.143, Texas Natural Resources Code, that I will use the services of a licensed water well driller as required under 16 Texas Administrative Code §6.105(a)(2) and I agree to plug the well upon abandonment."

(2) All shallow closed-loop geothermal injection wells shall be drilled and completed by a water well driller who holds a current and valid water well driller's license issued by TDLR. Prior to commencing operations for a shallow closed-loop geothermal injection well, an owner shall provide to the Director the name and TDLR license number of the TDLR water well driller.

(3) If the shallow closed-loop geothermal system utilizes a submersible pump, the submersible pump associated with the shallow closed-loop geothermal system shall be installed by a pump installer who holds a current and valid pump installer's license issued by TDLR. Prior to commencing installation of the pumps and other equipment, an owner shall provide to the Director the name and TDLR license number of the pump installer.

(b) Inventory. Drillers of shallow closed-loop geothermal injection wells authorized by rule shall inventory wells after construction by completing the TDLR state well report form and submitting the form to the Director within 30 days from the date the well construction is completed. Any additives, constituents, or fluids (other than potable water) that are used in the closed loop system shall be reported on the state well report form.

(c) Approval. A registration submitted under this section will be reviewed by the Commission's Special Injection Permits (SIP) Unit. The SIP Unit will notify the owner when the TDLR state well report form is approved by the Commission. The owner may operate the system as soon as the owner receives the SIP Unit's approval.

§6.106. Construction Standards.

(a) Siting and setback. All wells shall be located at least 10 feet from adjacent property lines and sewer lines, and at least 25 feet from potential sources of contamination that include but are not limited to septic tanks/fields, livestock pens, or material storage facilities.

(b) Surface completion. Water well drillers drilling a shallow closed-loop geothermal injection well shall place a concrete slab or sealing block above the cement slurry around the well.

(1) The slab or block shall extend at least two feet from the well in all directions and have a thickness of at least four inches. The slab or block shall be separated from the well casing by a plastic or mastic coating or sleeve to prevent bonding of the slab to the casing.

(2) The surface of the slab shall be sloped so that liquid drains away from the well.

(3) A pitless adapter may be used if:

(A) the adapter is welded to the casing or fitted with another equally effective seal; and

(B) the annular space between the borehole and the casing is filled with cement to a depth not less than 20 feet below the adapter connection.

(c) Commingling prohibited. All shallow closed-loop geothermal injection wells shall be completed so that aquifers or zones containing waters that are known to differ significantly in chemical quality are not allowed to commingle and cause degradation of any aquifer containing fresh water.

(d) Drilling and completion requirements.

(1) Casing. Temporary casing may be installed to prevent overburden cave-in prior to the installation of tubing material and grouting of shallow closed-loop geothermal injection wells. If temporary casing is not installed, the completion of well construction should proceed as soon as possible upon completion of the borehole. If temporary casing is installed, it shall comply with the following requirements:

(A) Steel well casing wall thickness shall be dependent on casing length and shall be determined using American Petroleum Institute (API) or American Water Works Association (AWWA) standards but in no circumstance shall have less than a .233-inch wall thickness.

(B) Plastic well casing or screen shall not be driven. Plastic well casing shall meet the requirements specified in the ASTM Standard F480, Standard Specification for Thermoplastic Well Casing Pipe and Couplings Made in Standard Dimension Ratios (SDR) as amended and supplemented. Plastic casing shall also meet the American National Standards Institute (ANSI) standards for "Plastic Piping System Components and Related Materials."

(C) If the use of a steel or polyvinyl chloride (PVC) sleeve is necessary to prevent possible damage to the casing, the steel sleeve shall be a minimum of 3/16 inches in thickness and the PVC sleeve shall be a minimum of ASTM D1785 Schedule 80 sun-resistant and 24 inches in length. Any sleeve shall extend 12 inches into the cement slurry.

(D) Shallow closed-loop geothermal injection wells are not required to be cased into bedrock.

(2) The water well driller shall backfill the annular space of a shallow closed-loop geothermal injection well from the surface to the total depth with grouting material in a manner that meets or exceeds good engineering practices and the gest current available technology. Grouting materials consist of a combination of bentonite, cement, thermally enhanced material, or a combination of such materials. In instances where boreholes will not support a grouting slurry, grouting alternatives, such as solid bentonite chip material may be used. Any other material used to backfill the annular space of a shallow-closed loop geothermal injection well must be approved by the Director.

(3) Where no groundwater or only one zone of groundwater is encountered during drilling, grouting alternatives may be used to backfill up to 30 feet from the surface The water well driller shall fill the top 30 feet with grouting or grouting alternatives that have been approved by the Director.

(4) At all times during the progress of work, the driller shall provide protection to prevent tampering with the well or introduction of foreign materials into the well.

(5) Borehole diameter shall, at a minimum, allow for the insertion of a pipe sized to ensure all concrete is properly located, distributed, and cured based on the overall design and operation of the shallow closed-loop geothermal injection well. Loop tubing shall be installed for the purpose of filling the annulus between the tubing and the borehole with sand and grout material.

(6) No section of the annulus between the heat exchange loop and borehole wall shall remain open after completion of the well.

(7) For heat exchange loop material and connection requirements, the applicable American Society for Testing and Materials (ASTM) standards for the polyethylene (PE) pipe material shall be used. The heat exchange loop shall not be forced into the borehole or past an obstruction in such a manner that the structural integrity of the tubing may be compromised. This includes but is not limited to instances of cave-in, bedrock dislodgement, partial blockage, or overburden.

(8) All heat exchange loop pipe connections to be placed in the borehole shall be connected by heat-fusion, electrofusion, or a similar joints process. In addition to heat fusion or electrofusion joints, non-metallic mechanical stab-type insert fittings shall meet applicable ASTM standards.

(9) Wells that use a plastic loop require the placement of a high solids bentonite slurry grout with at least 20 percent solids by weight for any depth interval of the boring that is in a confining or semi-confining layer containing significant silt and/or clay.

(10) If copper tubing is used for heat exchange applications, all below grade copper connections shall be joined by brazing using a filler material with a high melting temperature such as a material with 15% silver content or equivalent.

(e) Heat Transfer Fluids.

(1) Potable water, food grade propylene glycol, and USP-grade propylene glycol are the only antifreeze additives a water well driller may use for shallow closed-loop geothermal injection wells.

(2) Any deviation from the approved antifreeze additives requires an individual permit.

§6.109. Operational Standards.

(a) Safety. The system must clearly be marked identifying it as a shallow closed-loop geothermal system.

(b) Pressure testing. Shallow closed-loop geothermal injection wells shall be pressure-tested with water at 100 psi (690 kPa) for 30 minutes prior to backfilling of connection (header) trenches. Any leaking loop shall be repaired or replaced prior to completing the well.

(c) Local regulation. The Commission does not require the submittal of site plans for wells authorized by rule under this subchapter. However, a site plan may be required by a local health agent, other local governmental entity, and/or a groundwater conservation district.

§6.110. Well Reports.

(a) The water well driller is required by §76.70 of this title (relating to Responsibilities of the Licensee -- State Well Reports) to submit a well report to TDLR electronically through the Texas Well Report Submission and Retrieval System (TWRSRS). The driller shall provide an electronic copy of the well report to the Director within 30 days of well completion. A well report is not required for each well constructed on one site; however a map or drawing of each well shall be provided.

(b) At a minimum, a completed copy of the well report must include the following information for each well or wells drilled:

(1) the name and address of the owner of the well or wells;

(2) the county in which the well or wells were drilled;

(3) a list of any other wells drilled at the same time;

(4) the owner well number (if assigned);

(5) the Latitude/Longitude (WGS 84 datum in either Degrees/Minutes Seconds or Decimal Degrees) of the well or wells;

(6) the elevation (surface level of drill site expressed in feet above sea level);

(7) the drilling start date and end date (expressed in month/date/year);

(8) a schematic showing the borehole or boreholes' diameter in inches, the bottom depth in feet, and the drilling method;

(9) the driller's name;

(10) the water well driller's TDLR license number; and

(11) any additives, constituents, or fluids to make up the heat transfer fluid.

(c) Incomplete well reports may be subject to a notice of violation from the Commission. Failure to complete a well report within 30 days of a notice of violation may result in enforcement action.

(d) A shallow closed-loop geothermal system, once drilled, installed, and operating is a permanent fixture of the property. If the property is transferred, both the transferor owner and the transferee owner shall notify the Commission of the transfer within 30 days of the date of the transfer. The transferee owner shall be responsible for plugging the well upon abandonment.

(e) Texas Occupations Code §1901.251 authorizes the owner or the person for whom the well was drilled to request that information in well reports be made confidential. If such person seeks to request confidentiality, the person shall file a written request with the Commission via certified mail. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for materials 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 materials.

§6.111. Plugging.

(a) Upon permanent discontinued use or abandonment of a shallow closed-loop geothermal injection well, the owner shall plug the well according to the following standards:

(1) All removable casing shall be removed and the entire well shall be pressure filled with cement from bottom to the land surface using a pipe correctly sized to ensure all cement is properly located, distributed, and cured; and

(2) The well may be filled with fine sand, clay, or heavy mud followed by a cement plug extending from land surface to a depth of not less than ten feet below the land surface.

(b) Any fluids injected into the closed loop system shall not endanger fresh water.

(c) Not later than the 30th day after the date the well is plugged, a driller or well owner who plugs an abandoned well shall submit to the Commission a completed copy of the well plugging report filed with the TDLR electronically through the Texas Well Report Submission and Retrieval System (TWRSRS).

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Haley Cochran
Assistant General Counsel, Office of General Counsel
Railroad Commission of Texas
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For further information, please call: (512) 475-1295

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PART 2. PUBLIC UTILITY COMMISSION OF TEXAS

CHAPTER 24. SUBSTANTIVE RULES APPLICABLE TO WATER AND SEWER SERVICE PROVIDERS

SUBCHAPTER H. CERTIFICATES OF CONVENIENCE AND NECESSITY

16 TAC §24.233

The Public Utility Commission of Texas (commission) adopts amendments to 16 Texas Administrative Code (TAC) §24.233, relating to Contents of Certificate of Convenience and Necessity Applications with changes to the proposed text as published in the October 18, 2024, issue of the *Texas Register* (49 TexReg 8452) and will be republished. The amendments implement Texas Water Code §13.244 and §13.246 as revised by Senate Bill 893 during the Texas 88th Regular Legislative Session. The amendments grant the Executive Director authority to make minor corrections to water and sewer certificates of convenience and necessity without observing formal amendment procedures. The amendment is adopted under Project No. 57059.

The commission requested comments on the following question:

Under TWC §13.244(e)(4), the executive director may make a correction under this rule "to correct another similar non-substantive error or matter if authorized by the utility commission by rule." Are there any additional types of errors or matters that the commission should authorize the executive director to correct under the proposed rule?

The commission received comments on the proposed amendment from the Texas Association of Water Companies (TAWC). In response to the presented question, TAWC stated that instead of providing explicit listings of other non-substantive errors, it may be more prudent to include a catchall provision, which would allow the executive director to review CCNs on a case-by-case basis to review for such errors.

Commission Response

The commission disagrees with TAWC. The rule language is consistent with statute; allowing a catchall provision would exceed the changes made by SB 893 and could include changes that merit a full contested case proceeding.

Statutory Authority

The amendment is adopted under Texas Water Code (TWC) §13.041, which provides the commission with the authority to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction. The amended rule is also proposed under TWC §13.244 and 13.246 as amended by SB 893 (88th regular session), which provide the commission executive director to make minor corrections to water and sewer CCNs.

Cross Reference to Statute: TWC §§13.041, 13.244, and 13.246.

§24.233. Contents of Certificate of Convenience and Necessity Applications.

(a) Application. To obtain or amend a certificate of convenience and necessity (CCN), a person, public water or sewer utility, water supply or sewer service corporation, affected county as defined in §24.3(4) of this title (relating to Definitions of Terms), county, district, or municipality must file an application for a new CCN or a CCN amendment. Applications must contain the following materials, unless otherwise specified in the application form:

(1) the appropriate application form prescribed by the commission, completed as instructed and properly executed;

(2) mapping documents as prescribed in §24.257 of this title (relating to Mapping Requirements for Certificate of Convenience and Necessity Applications);

(3) information to demonstrate a need for service in the requested area, including:

(A) a copy of each written request for service received, if any; and

(B) a map showing the location of each request for service, if any;

(4) if applicable, a statement that the requested area overlaps with the corporate boundaries of a district, municipality, or other public authority, including:

(A) a list of the entities that overlap with the requested area; and

(B) evidence to show that the applicant has received the necessary approvals including any consents, franchises, permits, or licenses to provide retail water or sewer utility service in the requested area from the applicable municipality, district, or other public authority that:

(i) currently provides retail water or sewer utility service in the requested area;

(ii) is authorized to provide retail water or sewer service by enabling statute or order; or

(iii) has an ordinance in effect that allows it to provide retail water or sewer service in the requested area, if any.

(5) an explanation from the applicant demonstrating that issuance of a new CCN or a CCN amendment is necessary for the service, accommodation, convenience, or safety of the public;

(6) if the infrastructure is not already in place or if existing infrastructure needs repairs and improvements to provide continuous and adequate service to the requested area, a capital improvement plan, including a budget and an estimated timeline for construction of all facilities necessary to provide full service to the requested area, keyed to a map showing where such facilities will be located to provide service;

(7) a description of the sources of funding for all facilities that will be constructed to serve the requested area, if any;

(8) disclosure of all affiliated interests as defined by §24.3 of this title;

(9) to the extent known, a description of current and projected land uses, including densities;

(10) a current financial statement of the applicant;

(11) according to the tax roll of the central appraisal district for each county in which the requested area is located, a list of the owners of each tract of land that is:

(A) at least 25 acres; and

(B) wholly or partially located within the requested area;

(12) if dual certification is being requested, a copy of the executed agreement that allows for dual certification of the requested area. Where such an agreement is not practicable, a statement of why dual certification is in the public interest;

(13) if an amendment is being requested with the consent of the existing CCN holder, a copy of the executed agreement to amend the existing certificated service area;

(14) for an application for a new water CCN or a CCN amendment that will require the construction of a new public drinking water system or facilities to provide retail water utility service, a copy of:

(A) the approval letter for the plans and specifications issued by the TCEQ for the public drinking water system or facilities. Proof that the applicant has submitted plans and specifications for the proposed drinking water system is sufficient for a determination of administrative completeness. The applicant must notify the commission within ten days upon receipt of any TCEQ disapproval letter. If the applicant receives a TCEQ disapproval letter, the application for a new water CCN or a CCN amendment may be subject to dismissal without prejudice. Any approval letter for the proposed public drinking water system or facilities must be filed with the commission before the issuance of a new CCN or a CCN amendment. Failure to provide such approvals within a reasonable amount of time after the application is found administratively complete may result in dismissal of the application without prejudice. Plans and specifications are only required if the proposed change in the existing capacity is required by TCEQ rules;

(B) other information that indicates the applicant is in compliance with §24.205 of this title (relating to Adequacy of Water Utility Service) for the system; or

(C) a contract with a wholesale provider that meets the requirements in §24.205 of this title;

(15) for an application for a new sewer CCN or CCN amendment that will require the construction of a new sewer system or new facilities to provide retail sewer utility service, a copy of:

(A) a wastewater permit or proof that a wastewater permit application for the additional facility has been filed with the TCEQ. Proof that the applicant has submitted an application for a wastewater permit is sufficient for a determination of administrative completeness. The applicant must notify the commission within ten days upon receipt of any TCEQ disapproval letter. If the applicant receives a TCEQ disapproval letter, the application for a new sewer CCN or CCN amendment may be subject to dismissal without prejudice. Any approval letter for the permit application must be filed with the commission before the issuance of a new CCN or a CCN amendment. Failure to provide such approvals within a reasonable amount of time after the application is found administratively complete may result in the dismissal of the application without prejudice. Plans and specifications are only required if the proposed change in the existing capacity is required by TCEQ rules.

(B) other information that indicates that the applicant is in compliance with §24.207 of this title (relating to Adequacy of Sewer Service) for the facility; or

(C) a contract with a wholesale provider that meets the requirements in §24.207 of this title; and

(16) any other item or information required by the commission.

(b) If the requested area overlaps the boundaries of a district, and the district does not intervene in the docket by the intervention deadline after notice of the application is given, the commission will determine that the district is consenting to the applicant's request to provide service in the requested area.

(c) Application within the municipal boundaries or extraterritorial jurisdiction of certain municipalities.

(1) This subsection applies only to a municipality with a population of 500,000 or more.

(2) Except as provided by paragraphs (3) - (7) of this subsection, the commission may not grant to a retail public utility a CCN for a requested area within the boundaries or extraterritorial jurisdiction of a municipality without the consent of the municipality. The municipality may not unreasonably withhold the consent. As a condition of the consent, a municipality may require that all water and sewer facilities be designed and constructed in accordance with the municipality's standards for facilities.

(3) If a municipality has not consented under paragraph (2) of this subsection before the 180th day after the date the municipality receives the retail public utility's application, the commission will grant the CCN without the consent of the municipality if the commission finds that the municipality:

(A) does not have the ability to provide service; or

(B) has failed to make a good faith effort to provide service on reasonable terms and conditions.

(4) If a municipality has not consented under this subsection before the 180th day after the date a landowner or a retail public utility submits to the municipality a formal request for service according to the municipality's application requirements and standards for facilities on the same or substantially similar terms as provided by the retail public utility's application to the commission, including a capital improvement plan required by TWC §13.244(d)(3) or a subdivision plat, the commission may grant the new CCN or a CCN amendment without the consent of the municipality if:

(A) the commission makes the findings required by paragraph (3) of this subsection;

(B) the municipality has not entered into a binding commitment to serve the requested area before the 180th day after the date the formal request was made; and

(C) the landowner or retail public utility that submitted the formal request has not unreasonably refused to:

(i) comply with the municipality's service extension and development process; or

(ii) enter into a contract for retail water or sewer utility service with the municipality.

(5) If a municipality refuses to provide service in the requested area, as evidenced by a formal vote of the municipality's governing body or an official notification from the municipality, the commission is not required to make the findings otherwise required by this section and may grant the CCN to the retail public utility at any time after the date of the formal vote or receipt of the official notification.

(6) The commission must include as a condition of a CCN granted under paragraph (4) or (5) of this subsection that all water and sewer facilities be designed and constructed in accordance with the municipality's standards for water and sewer facilities.

(7) Paragraphs (4) - (6) of this subsection do not apply to Cameron, Hidalgo, or Willacy Counties, or to a county:

(A) with a population of more than 30,000 and less than 36,000 that borders the Red River;

(B) with a population of more than 100,000 and less than 200,000 that borders a county described by subparagraph (A) of this paragraph;

(C) with a population of 170,000 or more that is adjacent to a county with a population of 1.5 million or more that is within 200 miles of an international border; or

(D) with a population of more than 40,000 and less than 50,000 that contains a portion of the San Antonio river.

(E) The commission will maintain on its website a list of counties that are presumed to meet the requirements of this paragraph.

(8) A commitment by a city to provide service must, at a minimum, provide that the construction of service facilities will begin within one year and will be substantially completed within two years after the date the retail public utility's application was filed with the municipality.

(9) If the commission makes a decision under paragraph (3) of this subsection regarding the granting of a CCN without the consent of the municipality, the municipality or the retail public utility may appeal the decision to the appropriate state district court.

(d) Extension beyond extraterritorial jurisdiction.

(1) Except as provided by paragraph (2) of this subsection, if a municipality extends its extraterritorial jurisdiction to include an area in the certificated service area of a retail public utility, the retail

public utility may continue and extend service in its certificated service area under the rights granted by its CCN and this chapter.

(2) The commission may not extend a municipality's certificated service area beyond its extraterritorial jurisdiction if an owner of land that is located wholly or partly outside the extraterritorial jurisdiction elects to exclude some or all of the landowner's property within the requested area in accordance with TWC §13.246(h). This subsection does not apply to a sale, transfer, merger, consolidation, acquisition, lease, or rental of a CCN as approved by the commission.

(3) Paragraph (2) of this subsection does not apply to an extension of extraterritorial jurisdiction in Cameron, Hidalgo, or Willacy Counties, or in a county:

(A) with a population of more than 30,000 and less than 36,000 that borders the Red River;

(B) with a population of more than 100,000 and less than 200,000 that borders a county described by subparagraph (A) of this paragraph;

(C) with a population of 170,000 or more that is adjacent to a county with a population of 1.5 million or more that is within 200 miles of an international border; or

(D) with a population of more than 40,000 and less than 50,000 that contains a portion of the San Antonio river.

(E) The commission will maintain on its website a list of counties that are presumed to meet the requirements of this paragraph.

(4) To the extent of a conflict between this subsection and TWC §13.245, TWC §13.245 prevails.

(e) Area within municipality.

(1) If an area is within the boundaries of a municipality, any retail public utility holding or entitled to hold a CCN under this chapter to provide retail water and/or sewer utility service or operate facilities in that area may continue and extend service in its certificated service area, unless the municipality exercises its power of eminent domain to acquire the property of the retail public utility under this subsection. Except as provided by TWC §13.255, a municipally owned or operated utility may not provide retail water and sewer utility service within the certificated service area of another retail public utility without first having obtained from the commission a CCN that includes the area to be served.

(2) This subsection may not be construed as limiting the power of municipalities to incorporate or extend their boundaries by annexation, or as prohibiting any municipality from levying taxes and other special charges for the use of the streets as are authorized by Texas Tax Code §182.025.

(3) In addition to any other rights provided by law, a municipality with a population of more than 500,000 may exercise the power of eminent domain in the manner provided by Texas Property Code, chapter 21, to acquire a substandard water or sewer system if all the facilities of the system are located entirely within the municipality's boundaries. The municipality must pay just and adequate compensation for the property. In this subsection, substandard water or sewer system means a system that is not in compliance with the municipality's standards for water and wastewater service.

(A) A municipality must notify the commission no later than seven days after filing an eminent domain lawsuit to acquire a substandard water or sewer system and also notify the commission no later than seven days after acquiring the system.

(B) With the notification of filing its eminent domain lawsuit, the municipality, in its sole discretion, may either request that the commission cancel the CCN of the acquired system or transfer the certificate to the municipality, and the commission will take such requested action upon notification of acquisition of the system.

(f) Executive corrections. The executive director may make a correction to a CCN, at the discretion of the executive director or at the request of the CCN holder.

(1) An executive correction may be issued under this subsection only:

(A) to correct a clerical or typographical error;

(B) to correct a mapping error in a CCN:

(i) to reflect the metes and bounds of the certificated area on the map approved in a final order in a prior proceeding; or

(ii) to correct a typographical or grammatical error on the map approved in a final order in a prior proceeding.

(C) to change the name of an incorporated CCN holder on a CCN if:

(i) an amendment to the to the CCN holder's articles of incorporation or certificate of formation is filed with the secretary of state that only changes the name of the CCN holder; and

(ii) the CCN holder provides documentation from the secretary of state that the amendment only changed the name of the CCN holder.

(2) Commission staff will open a dedicated project for processing executive corrections under this subsection. Unless directed otherwise by commission staff on behalf of the executive director, all filings related to executive corrections must be made in this dedicated project.

(3) Request. A CCN holder may request the executive director make a correction under this subsection by filing a request for executive correction. The request must provide any information required for the executive director to determine whether to make the requested correction, including:

(A) a precise description of the requested correction;

(B) an explanation of the correction, including any applicable supporting documentation;

(C) a justification for making the correction by executive action rather than other available proceedings; and

(D) for a request to correct a mapping error under paragraph (1)(b) of this subsection:

(i) a list of any persons or entities whose retail service may be directly affected by the correction; and

(ii) a written agreement between the CCN holder any other retail water or sewer service provider whose service area is directly affected by the correction.

(4) Notice. For a request to correct a mapping error under paragraph (1)(B) of this subsection, commission staff will review the request and provide the CCN holder with a notice document. The CCN holder must provide the notice to any water or sewer service customers whose retail service is directly affected by the proposed correction. After providing notice, the CCN holder must file an affidavit specifying every person and entity to whom notice was provided and the date the notice was provided.

(5) Executive review. The executive director will issue an order granting, granting in part, or denying the requested executive correction.

(A) The executive director has discretion to determine whether to make an executive correction under this subsection. In evaluating whether to make an executive correction, the executive director will consider whether the requested correction is supported by appropriate documentation, whether it is appropriate to bypass any proceedings that would otherwise be required to make the requested correction, and any other factor deemed relevant by the executive director.

(B) The executive director must not make an executive correction to address a mapping error under paragraph (1)(B) of this subsection unless the CCN holder:

(i) files a written agreement between the CCN holder and any other retail water or sewer service provider whose service area is directly affected by the correction; and

(ii) provides notice of the correction to any water or sewer service customers whose retail service is directly affected by the correction.

(C) The executive director, or commission staff on behalf of the executive director, may request any additional information from the CCN holder necessary to determine whether to issue an executive correction under this subsection.

(D) The executive director's order may require commission staff or the CCN holder to take any actions or make any additional filings necessary to appropriately update the commission's records to accurately reflect the correction.

(E) If the executive director issues an executive correction, commission staff must notify the CCN holder that the correction has been made.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 19, 2024.

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Adriana Gonzales
Rules Coordinator
Public Utility Commission of Texas
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For further information, please call: (512) 936-7322

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CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS
SUBCHAPTER C. INFRASTRUCTURE AND RELIABILITY

16 TAC §25.56, §25.59

The Public Utility Commission of Texas (commission) adopts new 16 Texas Administrative Code (TAC) §25.56, relating to Temporary Emergency Electric Energy Facilities (TEEEF), and §25.59, relating to Long Lead-Time Facilities. The commission adopts these rules with changes to the proposed text as published in the June 28, 2024, issue of the *Texas Register* (49 TexReg 4672). The rules will be republished. New 16 TAC §25.56 establishes a process to allow a transmission and distribution utility (TDU) to lease and operate TEEEF to aid in restoring power to the TDU's distribution customers during a significant power outage. New 16 TAC §25.59 establishes a process for a TDU to procure, own, and operate, or enter into a cooperative agreement with other TDUs to procure, own, and jointly operate, long lead-time transmission and distribution facilities that will aid in restoring power to the TDU's distribution customers following a significant power outage. The new rules also provide for the recovery of costs associated with TEEEF and long lead-time facilities. The new sections are adopted in Project No. 53404.

The commission received comments on the proposed rule from AEP Texas, Inc. (AEP); the Alliance for Retail Markets (ARM) and Texas Energy Association for Marketers (TEAM) (filed collectively as the REP Coalition); CenterPoint Energy Houston Electric, LLC (CenterPoint); the City of Houston; the Electric Reliability Council of Texas, Inc. (ERCOT); ENGIE North America Inc. (ENGIE); Hunt Energy Network, LLC (HEN); Jupiter Power LLC (Jupiter); Lower Colorado River Authority Transmission Services Corporation (LCRA); the New Electric Technologies Policy Group (NET Policy Group); the Office of Public Utility Counsel (OPUC); Oncor Electric Delivery Company, LLC (Oncor); RPower, LLC (RPower); the Sierra Club; the Steering Committee of Cities Served by Oncor (OCSC); the Texas Advanced Energy Business Alliance (TAEBA); the Texas Competitive Power Advocates (TCPA); Texas Electric Cooperatives, Inc. (TEC); and Texas-New Mexico Power Company (TNMP).

Proposed §25.56, Temporary Emergency Electric Energy Facilities (TEEEF).Questions for Comment Along with the proposed rule, the commission issued three questions for stakeholder comment regarding the costs and benefits associated with implementation of proposed §25.56.Question 1 The commission's current precedent in distributed cost recovery factor proceedings addressing TEEEF costs is that "(a)bsent any applicable (c)ommission rule that provides otherwise, the determination of reasonableness and necessity must be made at the time the (c)ommission approves the (TEEEF) costs." (See Docket No. 53442, Item 166). The proposed rule, instead, requires a TDU to obtain preapproval for the amount of TEEEF generating capacity the TDU seeks to lease and defers the commission's evaluation of the reasonableness and necessity of the TDU's TEEEF costs to the TDU's next comprehensive base rate case. OPUC recommended that the reasonableness, necessity, and prudence review of TEEEF costs occur during the commission's review of a TDU's requested TEEEF capacity. AEP recommended the review occur when TEEEF costs are first being included in rates. Conversely, Hunt Energy, NET Policy Group, Engie, OCSC, Oncor, City of Houston, CenterPoint, LCRA, REP Coalition, RPower, Jupiter Power, and Sierra Club recommended that such a review of TEEEF costs not occur during the commission's review of a TDU's requested TEEEF capacity, but instead occur at a later proceeding, such as a base rate case.

Commission Response

The commission agrees with the majority of commenters that review of TEEEF costs should occur during the TDU's base-rate case, consistent with the commission's standard ratemaking practices. Specifically, TEEEF costs will be reviewed for reasonableness, necessity, and prudence in the TDU's base-rate proceeding unless the presiding officer finds good cause for doing so in another proceeding, such as a standalone TEEEF rider proceeding. This structure allows the commission to obtain and review all costs and information relevant to TEEEF leasing and utilization, including the characteristics of each TEEEF in the TDU's fleet, before committing ratepayers to shouldering those costs.

The commission declines to conduct a prudence review of TEEEF costs during the pre-approval process, because a TDU would not yet have leased any TEEEF, and the commission would not be able to fully evaluate the costs of the TEEEF or whether the TDU utilized the TEEEF appropriately during any qualifying significant power outages that occurred in its service territory. This would risk unduly delaying a TDU's leasing of TEEEF, incurring unnecessary costs to ratepayers, and potentially impairing the viability of TEEEF as a reliability and resiliency measure.

The commission also declines to conduct its prudence review of TEEEF costs when those costs are first being put into rates, because this would extend the length of interim rate proceedings unnecessarily. The most efficient time to review TEEEF costs for reasonableness, necessity, and prudence is during a TDU's base-rate case, when those costs can be fully reviewed and scrutinized in a contested case proceeding.

The commission also adds new §25.56(j)(1)(I) to allow a TDU that received commission approval of its TEEEF generating capacity prior to the effective date of this rule to request reductions of commission-approved TEEEF generating capacity through a subsequent TEEEF rider proceeding. This language is primarily included to provide a TDU that leased TEEEF prior to the development of the preapproval process to right-size its leased TEEEF fleet or otherwise reduce recovery for TEEEF costs already approved for recovery.

Question 2a

Should a TDU be required to obtain commission approval before entering into, renewing, or extending a lease involving a TEEEF? What are the advantages and disadvantages of such a requirement? The majority of stakeholders that answered Question 2a commented in support of requiring TDUs to seek commission approval before entering into, renewing, or extending a lease involving TEEEF. Specifically, stakeholders endorsed commission review and approval of a TDU's requested capacity for TEEEF leases. CenterPoint and AEP commented that the preapproval proceeding should be optional for TDUs. TEC, Calpine, ERCOT, and OCSC had no response to Question 2a. Stakeholders that commented in support of the preapproval proceeding noted that the primary benefits are transparency and accountability for the reliability, cost-effectiveness, and performance of TEEEF, as well as transparency around a TDU's overall preparedness for significant power outages. Some commenters expressed concern around ensuring that the competitive ERCOT market is not adversely affected by TEEEF utilization.

Commission Response

The commission agrees with the majority of commenters that a TDU should be required to obtain commission approval for a specific amount of capacity before a TDU enters into, renews, or extends a lease involving a TEEEF. Accordingly, the commission declines to modify the proposed rule to make the preapproval proceeding optional as requested by CenterPoint and AEP.

Question 2b

If the rule should contain a pre-approval process, what is the appropriate level of granularity for the commission's review? For example, should the commission pre-approve the sizes and types of units the TDU seeks to lease?

Oncor, AEP, TNMP, and CenterPoint opposed adding further granularity to the commission's review of TEEEF capacity unless the inclusion of such granularity would be optional. All other stakeholders that answered Question 2b supported the inclusion of additional detail in the preapproval proceeding and provided recommendations for additional factors the commission should evaluate. TEC, Calpine, ERCOT, and OCSC had no response to Question 2b.

The factors recommended by stakeholders in response to Question 2b included, in order of highest support: TEEEF capacity in megawatts (MW) (6); the size of individual TEEEF units in MW (6); fuel type of TEEEF units (6); resiliency plan implementation and other measures a TDU is evaluating, or in the process of implementing, for resiliency (3); past TEEEF lease renewals and extensions (3); distributed energy resource (DERs) and demand response integration (2); past TEEEF usage and whether TEEEF procured is used and useful (2); a review of the procurement and competitive bidding process (2); the mobility of the requested TEEEF units (2); review of a TDU's past TEEEF after-action reports (1); a review of the number of TEEEF units sought (1); the TDU's circuit segmentation study or capability (1); the TDU's other distribution investments (1); a review of the TEEEF lease itself (1); TEEEF operations and maintenance costs (1); the presence and frequency of extreme weather in the TDU's service territory (1); whether the TDU directly serves critical loads or substations (1); compliance with PURA §39.918 (1); the costs of TEEEF to ratepayers (1); and review of past TEEEF leases (1).

Commission Response

In response to commenters' feedback, the commission expands the scope of the preapproval proceeding, and, consequently, the contents of a TDU's application for TEEEF under proposed §25.56(c)(1), to better align with the primary goals of the proceeding. Specifically, in addition to requiring preapproval of the total amount of TEEEF capacity that a TDU is authorized to lease and the number of years the TDU is authorized to lease it, the commission also requires the TDU to indicate the functions that it intends its leased TEEEF fleet to perform. This overall approach will provide the TDUs with flexibility to freely enter into multiple leases, as market conditions dictate, so long as they do not exceed the capacity cap the commission sets for each function of TEEEF and their contracts do not extend past the date the commission authorizes. Additionally, it ensures that the ratepayers are protected from shouldering costs, should a TDU lease more TEEEF capacity than is required to perform a particular function.

To ensure the commission has sufficient information to support the aforementioned determinations, the commission revises the rule to require additional information of a pre-approval applicant, much of which was recommended by commenters. Generally speaking, the commission accepted recommendations that directly supported the above pre-approval structure and did not accept those that did not. Specifically, the commission requires the TDU to submit information on its history with TEEEF, such as prior authorizations, current TEEEF leases, prior after-action reports, etc. This information will allow the commission to evaluate how the TDU has used TEEEF in the past and whether or not additional TEEEF - for those that have leased TEEEF previously - is reasonable and necessary in the future.

The commission also requires the applicant to indicate the different characteristics that an individual TEEEF unit needs to fulfill each of the functions for which it is requesting TEEEF. While, in most cases, the commission will not impose specific technical requirements on the types of TEEEF a TDU can lease, it will ensure that a TDU is being thoughtful about its TEEEF needs and allow the commission to later verify that the TDU has prudently acquired appropriate TEEEF. For example, if a TDU indicates that a particular function requires TEEEF of a certain capacity or mobility to perform a function, and it does not acquire TEEEF with those characteristics, there will be a strong presumption that the TDU did not prudently select its leased TEEEF units. Accordingly, the commission modifies the rule by adding new §25.62(j)(5) to clarify that if a TDU is not utilizing its TEEEF prudently and as authorized, the commission can disallow costs associated with that TEEEF.

Finally, the TDU will have to provide evidence of the reasonableness and necessity of leasing TEEEF for each function for which it is requesting authorization. This will include providing any relevant information about other related efforts it is making, such as implementing a system resiliency plan.

HEN expressed concern that the procurement of TEEEF by TDUs, instead of competitive entities, represents a "first step in the re-verticalization of the industry." HEN recommended that the commission "carefully weigh the absolute amount of needed emergency generation," while taking resiliency considerations under §25.62, circuit segmentation studies under PURA §38.078, customer-sited back up generation under PURA §34.0204, and flexible load resources into account. Specifically, HEN recommended that a TDU be required to justify the amount of TEEEF procured against potential investments into optimizing its distribution system. HEN also recommended that the preapproval process include a holistic, comparative review of the distribution system with TEEEF versus third-party owned generation, storage, and load control assets to minimize customer costs and more effectively implement legislative initiatives.

RPower opposed involving TDUs in power generation and commented that Hurricane Beryl has made clear the shortcomings of allowing such involvement. RPower asserted that competitive on-site generation "is the proven and best resilience solution for customers" and that commission electric market rules should accordingly support and promote such generation instead of TEEEF. RPower questioned whether mobile generation is truly mobile given potential delays and permits required for transport and commented that such a process is an inefficient use of ratepayer funds. RPower commented that TEEEF sited at substations that serve as feeder hubs should not be the priority given the propensity for significant power outages to affect aerial distribution lines. RPower commented that, based on its own experience, competitive generators are better suited to arrange resilient generation sited at substations than TDUs leasing TEEEF. RPower recommended enhancing competitive market policies for resilient power generation by removing barriers to market expansion and prohibiting TDUs from becoming involved in competitive generation. Specifically, RPower recommended the commission allow for residential microgrids to be provided competitively by authorizing the interconnection of competitive resilience generators to serve large residential areas close to, but upstream of, individual residential meters.

Engie commented that "institutionalization of resource procurement in the ERCOT Region with pre-approved purchases and leasing by regulated utilities" outside competitive forces must be strenuously and frequently reviewed to ensure the scope and costs of such leases are limited only to what is strictly necessary to address the highly specific need of temporary emergency power on the distribution system. Engie emphasized the importance of avoiding burdening ratepayers with unnecessary costs, preventing excessive non-competitive obligations, and avoiding disruptions and distortions from affecting the ERCOT market.

Commission Response

The commission notes that PURA §39.918 does not direct the commission to determine whether or when a TDU is permitted to lease or energize TEEEF. The use cases for TEEEF energization are expressly laid out in the statute. Accordingly, the commission cannot, by rule, reduce these use cases or overrule a TDU's statutory authorization to utilize TEEEF in favor of competitive onsite generation, residential microgrids, or other third-party solutions.

However, the commission generally agrees with commenters that protecting ratepayers from bearing unnecessary costs and preventing regulated entities from disrupting the competitive market are also essential objectives. The adopted rule addresses these concerns by including a robust pre-approval process that ensures that a TDU only acquires TEEEF to energize in statutorily-approved use cases. Additionally, subsection (f)(4) of the adopted rule mirrors the statutory requirement of PURA §39.918 that TEEEF energization must not be included in ERCOT's locational marginal price calculations, pricing, or reliability models.

The commission also declines to conduct a review of the distribution system as recommended by HEN and declines to implement the policies recommended by RPower because they are out of scope of PURA §39.918.

Question 3

Proposed §25.56(f)(9) requires a TDU to file an after-action report with the commission following each TEEEF deployment. The commission requests comments on the proposed required contents of these after-action reports. Specifically, should the TDU be required to provide more granularity on the size and types of units deployed? Conversely, should the TDU be required to provide information on any leased TEEEF that was not deployed, and why?

AEP generally opposed the inclusion of additional criteria in a TDU's TEEEF after-action report. CenterPoint responded that certain additional criteria could be included in the after-action report "if practicable." Oncor provided lists of criteria it found reasonable and unreasonable to include in after-action reports. RPower generally stated that a TDU's after-action report should have additional granularity "on functions that are outside of the core business of electricity delivery and that generally are better provided by the competitive market." TEC, Calpine, ERCOT, and TNMP had no response to Question 3. Comments by HEN, OPUC, the City of Houston, LCRA, the REP Coalition, TCPA, TAEBA, and the Sierra Club are reflected in the list of recommended factors below.

The factors recommended by stakeholders in response to Question 3 included, in order of highest support: the size of individual TEEEF units in MW (9); fuel type of TEEEF units utilized to address the significant power outage (6); a rationale explaining why TEEEF units were not deployed (6); the fuel type of TEEEF units that were not utilized to address the significant power outage (6); the size of individual TEEEF units in MW that were not deployed

(5); the date and duration of deployment including the start and end times (4); a confirmation that TEEEF did not sell energy or ancillary services (4); TEEEF usage or output in MW (3); the locations of TEEEF deployment (3); whether the TEEEF units deployed are directly leased by the TDU or were procured under a mutual assistance program, including the name of the loaning TDU (3); a statement indicating whether each TEEEF unit was interconnected behind the meter or at a substation (3); the service each TEEEF unit provided such as demand response, load shed, bulk power restoration, critical infrastructure support, etc. (2); the costs of TEEEF deployment (2), the number of transmission customers served by TEEEF if any (2), a description of the events that resulted in a significant power outage (2); a confirmation that retail usage was not adjusted, or an explanation why retail usage was adjusted (2); details regarding data corrections for retail usage adjustments such as whether adjustments were necessary, the date of corrections, and methodology, and an opportunity to issue requests for information to TDUs regarding the same (2); the time to transport or prepare TEEEF prior to deployment (2); when decision to deploy or not to deploy TEEEF was made (2); the Electronic Service Identifiers (ESI IDs) affected by TEEEF deployment (2); lessons learned from TEEEF deployment (2); the costs and service impacts that TEEEF deployment caused distribution customers in relation to the benefits received (1); the number of distribution customers served by TEEEF (1); the number and capacity of generators or load resources affected by TEEEF deployment (1); the number and type of critical load, customers, or facilities served by TEEEF (1); details regarding whether the significant power outage impacted critical customers (1); the length of time an affected area was isolated (1); operational, logistical, or regulatory challenges associated with TEEEF deployment (1); and alternative restoration technology or resources that could be provided by the competitive market (1).

Commission Response

Of the additional factors recommended by stakeholders for the TEEEF after-action report, the commission adds, as applicable: the estimated number of affected distribution customers served by TEEEF; the size of individual TEEEF units in MW and the fuel type of TEEEF units energized, or not energized, to address the significant power outage; a rationale explaining why TEEEF units were not deployed, if any; whether the TEEEF units utilized are directly leased by the TDU or procured under a mutual assistance agreement or program.

Additionally, the commission adds requirements for a TDU to specify in its after-action report: the estimated number of distribution customers, and estimated load in MW, that experienced the significant power outage, and the estimated number of which that were served by TEEEF; information on the duration of service interruptions on critical customers the number and nameplate generating capacity, in MW, of generators or load resources that were isolated by TEEEF energization; information regarding TEEEF that were, or were not, energized including size, fuel type, connection configuration, mobile capability, and function; and whether the TDU procured any TEEEF under §25.56(d) or through a mutual assistance agreement or program.

The commission also notes commenter concerns regarding the requirements that a TDU is required to provide information on why individual TEEEF units were not energized in response to an eligible significant power outage in its service territory. Specifically, Oncor notes that "the decision (to not deploy a specific TEEEF) requires coordination and multiple conversations among different groups of personnel" and "would be cumbersome for the TDU to track in real time." The commission agrees with Oncor's statement that "the TDU's priority at that critical time should be on restoring power as swiftly as possible, and attention should not be diverted from critical restoration efforts to capture and track this unnecessary detail for reporting purposes." This is why the commission only requires a "brief summary" of the reasons why particular TEEEF units were not deployed. In many instances, this summary may be, for example, that a particular group of TEEEF units was leased to serve a different commission-authorized function and were not intended to respond to the particular crisis.

The commission clarifies that the purpose of this reporting requirement is not to relitigate each operational decision of a TDU to energize or not energize any particular TEEEF unit during a particular outage. The commission appreciates that responding to outages requires operators to make a large number of nuanced decisions in real time. However, if a number of units that would reasonably have been expected to be energized in a particular situation were not, or there is an apparent pattern of failure to utilize leased TEEEF across multiple outages, that calls into question whether the correct TEEEF was leased, whether a TDU's plan was adequate, and whether the TDU made appropriate preparations for that particular event.

Accordingly, many of the types of issues that are of highest concern to the commission are not the types of concerns that would require TDU operators to focus on documenting nuanced decisions in real time, drawing them away from critical restoration efforts. For example, whether there was fuel available for a particular unit, where a unit was prepositioned before an event, the function the unit was leased to perform, whether a unit was technically capable of being energized in a particular circumstance, and how the unit was incorporated into a TDU's system restoration planning are all details that should be identifiable outside of the context of a particular event.

Proposed §25.56(a) - Applicability

Proposed §25.56(a) establishes that the section is applicable to TDUs, other than river authorities, that operate distribution facilities in the ERCOT region to serve distribution customers.

OPUC and LCRA recommended proposed §25.56(a) be revised so the rule would also apply to river authorities. Both commenters noted that PURA §39.918 does not prohibit a river authority from leasing or operating TEEEF, and LCRA noted that the statute generally authorizes all TDUs to utilize TEEEF. LCRA also commented that the proposed rule unreasonably discriminates against LCRA by singularly excluding it from utilizing TEEEF for system reliability.

LCRA commented that PURA §39.918 was amended by House Bill 1500 during the 88th Texas Legislative Session to expand "widespread power outage" to "significant power outage" which therefore addresses circumstances where LCRA could meaningfully assist in reducing the impact of such outages on distribution customers. Specifically, LCRA noted that, consistent with PURA §39.918(a)(1)(C), some distribution customer loads on its system are fed radially which increases the risk of loss of service to such customers if a transmission-level outage occurs. LCRA also stated that excluding LCRA may affect smaller electric cooperatives and MOUs that operate at the distribution level and receive transmission service from LCRA. LCRA argued that such entities that ordinarily would not be able to procure or operate TEEEF would benefit from LCRA doing so.

LCRA additionally noted that LCRA "is a TDU and ERCOT designated transmission operator for 47 TDSPs" and is required to manually shed load when instructed by ERCOT. LCRA noted that, because TEEEF is classified as generation, electric cooperatives, MOUs, and non-ERCOT utilities are not prohibited by statute from deploying TEEEF within their service areas. However, PURA §39.918 is the only basis for allowing TDUs to lease and operate TEEEF for activities like system restoration. Finally, LCRA argued that LCRA being eligible to apply for TEEEF would reduce the impact of significant power outages on a greater area of Texas, including rural communities and areas not served by other utilities. OPUC agreed that reliability would be served by extending the rule to include river authorities.

Commission Response

The commission agrees with OPUC and LCRA and revises the rule to include river authorities. PURA §39.918(b)(1)(A) and (B) do not expressly prohibit river authorities from leasing and operating TEEEF. Moreover, river authorities are included in the definition of "transmission and distribution utility" under PURA §31.002(19). To the extent that other provisions of PURA §39.918 apply to retail customers, those obligations and requirements would not directly apply to river authorities, but instead would apply to the distribution service provider for which the river authority provides transmission service.

Proposed §25.56(b) - Definition

Proposed §25.56(b) establishes the definitions for "Significant power outage" and "Temporary Emergency Electric Energy Facility (TEEEF)" for the section.

OPUC and Oncor recommended the definition of "significant power outage" under proposed clause §25.56(b)(1)(C)(i) be revised for clarity. Specifically, OPUC recommended the phrase "affects a significant number of (customers)" be revised to be more informative. OPUC explained that the phrase does not provide sufficient guidance to TDUs to determine when an outage is significant and that the provision could be revised to be more objective. As an alternative, OPUC recommended that the provision be revised to qualify "significant power outage" as losses of electric power that affect 10% or more customers in a region served by the TDU. OPUC commented that this proposed definition mirrors the percentage threshold used to define "major events" under §25.52(c)(4)(D), relating to Reliability and Continuity of Service.

In contrast, Oncor commented that the proposed definition for "significant power outage" is sufficient, but recommended revisions if the commission were to revise the language based on comments from other stakeholders. Specifically, Oncor recommended utilizing the term and definition of "interruption, significant" from §25.52(c)(7) in lieu of the term "significant power outage." Oncor explained that the definition of "interruption, significant" is sufficiently flexible to apply to TDUs of differing sizes, customer counts, resource types, and geographies, and is therefore preferable to the proposed threshold of "10% or more of the customers in a region" in §25.52(c)(4)(D). Oncor further commented that the definition of "major events" §25.52(c)(4)(D), proposed for inclusion by OPUC, is only used to "classify different causes of energy emergencies" and is otherwise separate from the language used in proposed §25.52(c)(7) that determines whether an interruption is significant.

Commission Response

The commission declines to modify the rule to make any changes to the definition of "significant power outage." The definition of "significant power outage" as defined under §25.56(b)(1) adheres to the language provided by PURA §39.918(a)(1) and (2). Because this definition defines the acceptable use cases for TEEEF, the commission elects to mirror the statutory language in the rule.

The commission does not share OPUC's concern regarding the ambiguity of what constitutes a significant power outage. The statutory language provides sufficient guidance on when TEEEF should be deployed. Any precise standard would risk disqualifying or discouraging the use of TEEEF during a potentially life-threatening situation. In areas where the statutory language, the commission provides discretion to the TDU and expects the TDU to use that discretion reasonably.

Furthermore, each TDU will have to provide examples of the significant power outages that have occurred in its service territory when requesting authorization to lease TEEEF, which will give the commission the ability to ensure that the TDU's view of what constitutes a significant power outage is reasonable for purposes of how much TEEEF should be leased. This provides protection from ratepayers. And, when an actual outage occurs, the commission does not want the TDU to have to worry about whether, for example, a certain number or percentage of its distribution customers are affected by the outage. Similarly, if a TDU reasonably projects that a power outage is going to last for six hours, the possibility that the TDU may be able to restore power in five and a half hours, should not discourage them from deploying TEEEF, as appropriate.

REP Coalition recommended revising the definition of TEEEF in proposed §25.56(b)(2) in a manner that is more consistent with the more specific definition under PURA §39.918(b)(1) to "avoid any incongruence between the (enabling) statute and the rule." Specifically, REP Coalition recommended adding the language of PURA §39.918(b)(1)(A) and (B) to proposed §25.56(b)(2).

Commission Response

The commission declines to implement REP Coalition's recommended change to largely incorporate the description of when a TEEEF is permitted to be used into the definition of TEEEF because it is redundant. Other substantive provisions of the rule clearly outline under what circumstances TEEEF may be energized. The intended function of this definition is merely to clarify what type of facilities the noun "TEEEF" refers to, which is necessary because it is a novel phrase.

REP Coalition and Oncor recommended the term "deploy" or "deployment" be defined. Specifically, REP Coalition recommended the term "deployment" be defined in a manner that clearly indicates a TEEEF deployment includes the operation of TEEEF and not just the relocating of a TEEEF in anticipation of a significant power outage. REP Coalition provided draft language consistent with its recommendation.

Oncor recommended the term "deploy" should be defined specifically for proposed §25.56(f)(9) as "the act of mobilizing a TEEEF during or in anticipation of a significant power outage in preparation to serve a customer during such significant power outage, regardless of whether the TEEEF is ultimately energized." Oncor commented that its proposed definition would assist in differentiating when TEEEF is actually utilized for serving customers during significant power outages in accordance with PURA §39.918 as opposed to when a TDU simply relocates TEEEF during normal operations. Oncor provided draft language consistent with its recommendation.

Commission Response

The commission declines to add a definition of "deploy" or "deployment" to §25.56(b) and instead replaces all instances of the terms "deployment" and "deploy" in the rule with "energization" and "energize," respectively. This change addresses commenters' concerns by clarifying that TEEEF may be "energized" if a significant power outage under §25.56(b)(1) exists and one of the conditions under §25.56(f)(1)(A) or (B) are met. The commission also makes revisions to when a TDU is obligated to submit an after-action report to the commission under the heading for §25.56(f)(10) to not depend upon when energization occurs.

Proposed §25.56(c) - Commission review and approval of TEEEF generating capacity

Proposed §25.56(c) establishes a contested case proceeding in which a TDU that seeks to enter into, renew, or extend a lease for TEEEF generating capacity must submit an application for commission review and approval.

OCSC requested additional clarity on the contested case proceeding for commission approval of TEEEF generating capacity requested by TDUs under proposed §25.56(c). OCSC noted that, as proposed, the process more resembles an administrative approval rather than a contested case proceeding. OCSC further commented that it is not clear whether the review of TEEEF generating capacity under proposed §25.56(c) is the same or separate from the TEEEF cost recovery rider proceeding. OCSC accordingly requested the commission revise the proposed rule to specify whether the TEEEF rider and review of TEEEF generating capacity are interrelated or not.

Commission Response

The commission substantively revises §25.56(c) to include features more indicative of a contested case proceeding. Specifically, the commission revises §25.56(c)(2) to include sufficiency criteria, streamline the commission review and staff recommendation timeline, and provide notice and intervention deadlines.

In response to OCSC's request for clarification, the commission review under §25.56(c) is a separate proceeding from the TEEEF rider proceeding. The commission's review under §25.56(c) is a front-end proceeding concerns a TDU's requested TEEEF capacity before the TDU enters into a lease, while a TEEEF rider proceeding serves as a vehicle to request to include TEEEF costs into rates.

Proposed §25.56(c)(1) - Contents of TEEEF application

Proposed §25.56(c)(1) requires a TDU to submit an application to the commission for pre-approval of TEEEF generating capacity and establishes the required contents of the application.

Sierra Club and TAEBA commented on their concerns surrounding the leasing, costs, and deployment of TEEEF, as well as the associated impacts on ratepayers.

Sierra Club recommended that TEEEF deployments and performances be carefully reviewed to determine whether ratepayers should be responsible for the cost of such facilities. Sierra Club also emphasized that the costs and degree of oversight and deployment of TEEEF are subjects of concern for ratepayers. Sierra Club recommended the usage of customer-sited DERs, demand response capabilities, microgrids, backup power packages (such as those authorized by the Texas Energy Fund), and the Aggregated DER pilot project as more cost-effective and resilient solutions than TEEEF, which are "utilized by a monopoly and not subject to normal competitive forces." Sierra Club noted that "there is a potential for misuse (of TEEEF) in part because of misalignment between the need for these facilities and the ability of TDUs to recover not only the cost of the leasing and operation of the generators, but also a rate of return on those leases and operations, as they are treated as a capital asset." Sierra Club also commented that TEEEF could incur additional system-wide costs through increased transmission and distribution costs to integrate such facilities into the grid.

TAEBA expressed concern regarding the costs and potential lack of oversight of TEEEF. TAEBA requested the commission place a greater emphasis on the development of Distributed Energy Resources (DERs) for cost-effectiveness and resilience. TAEBA highlighted that TEEEF are a significant burden for ratepayers because the costs not only include leasing and deployment, but also a rate of return because TEEEF leases are treated as a capital asset. TAEBA also commented that TEEEF may also drive increased transmission and distribution costs due to issues surrounding integration of such facilities. TAEBA noted that the TEEEF regulatory framework has effectively recreated a cost-of-service business model that was intended to be replaced by competition and customer choice. TAEBA commented that DERs provide a more customer-oriented, decentralized, and resilient approach to grid reliability, which may be more cost-effective. TAEBA pointed out that DER costs deployed through competitive market forces are not borne by a TDU's ratepayers. TAEBA noted that DERs reduce transmission losses and alleviate stress on the grid during peak demand periods because such facilities are located closer to the point of delivery. TAEBA further commented that many DERs have zero fuel costs and that social investment into DERs would be a more effective use of ratepayer money than TEEEF.

Commission Response

The commission agrees that protection ratepayers from excessive TEEEF-related costs is important and notes that §25.56 contains numerous guardrails to address such cost concerns. First is the addition of a robust pre-authorization process that approves not only the capacity but also the functions that leased TEEEF can serve will help ensure that TDUs lease a reasonable amount of TEEEF. This process is not required by statute and will be conducted as contested cases to ensure that stakeholders have sufficient input before the leasing of TEEEF even begins. Additionally, after each TEEEF energization, a TDU will be required to submit an after-action report to the commission that includes a variety of details regarding each individual energization. Lastly, all TEEEF costs will be reviewed for reasonableness and necessity at the TDU's next comprehensive base-rate proceeding where imprudent TEEEF investments will be excluded from a TDU's cost recovery and rate of return.

The foregoing processes ensure that there is continuous and comprehensive review of TEEEF while still providing TDUs the discretion and flexibility required to address potentially life-threatening power outages.

The commission also declines to require or explore other solutions, such as demand-side solutions, as recommended by commenters, because these solutions are beyond the scope of this rulemaking project. Further, as described above, TDUs have statutory authorization to lease TEEEF and the commission cannot overrule that authorization by rule.

Sierra Club recommended revising proposed §25.56(c)(1) to ensure that TEEEF is only deployed when necessary and deployed effectively when it is. Accordingly, Sierra Club recommended the commission first make certain that "competitive and customer-sited resources are used to restore power, and then TEEEF resources are used as needed."

NET Policy Group recommended the commission consider alternatives to TEEEF because such facilities are inefficient and costly and are used intermittently for less than 100 hours approximately every 10 years. Specifically, NET Policy Group recommended TDUs leasing emergency backup services from a competitive generator, which would allow the generator to participate in the wholesale market during non-emergency conditions. To that end, NET Policy Group recommended using Senate Bill 415 (87R) as a template for such a leasing arrangement.

TAEBA commented that the benefits of the proposed rules are questionable because experiences from Hurricane Beryl have demonstrated that TEEEF may not be available or effective when needed most." TAEBA stated that the proposed rules lack sufficient mechanisms to ensure that TEEEF deployment is cost-effective and truly necessary." TAEBA emphasized that TEEEF should be utilized only as a last resort when competition has failed to provide a better solution.

Jupiter Power commented that TEEEF should only be used in critical emergency situations as a last resort to provide power to consumers because such facilities are not competitively owned and are directly paid for by ratepayers. Jupiter Power emphasized transparency on TEEEF procurement to ensure that consumers and the competitive market are not encumbered, particularly in instances where TEEEF is not deployed.

Commission Response

The commission declines to implement the recommended changes, because they are not consistent with PURA §39.918. PURA authorizes TDUs to lease TEEEF and provides specific scenarios in which TDUs are permitted to use this TEEEF to aid in the restoration of power. This direct statutory authorization does not require TEEEF to be deployed as a last resort in the manner Sierra Club, TAEBA, and Jupiter Power recommend. PURA also does not permit the commission to consider other alternatives instead of TEEEF, as NET Policy Group suggests. Additionally, in the context of a potentially life-threatening outage, the commission expects TDUs to bring their resources to bear in the manner that is most effective in restoring power in its service territory. Relegating a critical facility to a measure of last resort may interfere with a TDU's ability to do so.

However, the adopted rule substantively addresses stakeholder concerns by providing a robust preapproval process that will ensure each TDU only leases TEEEF that is reasonable and necessary to restore power in it service territory. As previously discussed, the commission's preapproval process will consider other measures the TDU is implementing, such as a systems resiliency plan, that may mitigate the need for TEEEF capacity. Furthermore, the commission retains authority to disallow any TEEEF-related expenses that are not prudently incurred or that are associated with TEEEF that is not prudently used.

Finally, in response to NET Policy Group recommendation that the commission allow TDUs to lease emergency backup generation from competitive generators, this is not permitted under statute. The ability to lease TEEEF is an exception to the general statutory prohibition against TDUs utilizing generation or otherwise participating in the competitive market.

OPUC recommended proposed §25.56(c)(1) include a requirement that the TDU provide notice of a TEEEF application under proposed §25.56 to OPUC within 10 days of filing the application. OPUC commented that TEEEF leases would impact residential and small commercial consumers, therefore it is appropriate for OPUC to be notified of each application so that it may more effectively represent those customer classes and support the commission and TDU's emergency operations efforts.

Commission Response

The commission agrees with OPUC and adds a requirement for TDUs to notify OPUC of a TDU's application for authorization to lease TEEEF as part of the general notice and intervention requirements.

OPUC, REP Coalition, and TCPA recommended the commission approval of TEEEF capacity include additional criteria. OPUC recommended the application include the: "type of facility and total generating capacity of each TEEEF; total cost and duration of the lease, extension, or renewal; whether a competitive bidding process was used to lease the facility; an explanation as to whether the TEEEF will directly serve residential load or other types of distribution-level customers, or if the TEEEF is intended to support infrastructure instead; details as to how the TDU intends to use the TEEEF, such as the region in which the TEEEF will be stationed; critical facilities or customers intended to be served; and amount of load, in MW, that is expected to be served; and for renewals or extensions, documentation that supports past performance, as proposed by staff, including the dates and descriptions of past significant power outages, including the magnitude and duration of the event; deployment of the TEEEF during each event; and load served during each event by location deployed, if more than one.

Similarly, REP Coalition recommended §25.56(c)(1)(A) be revised to include specific criteria for TEEEF such as use cases, plans and procedures for TEEEF deployments, any alternatives to TEEEF and justification for TEEEF usage, and an explanatory comparison of why the requested TEEEF capacity is necessary in relation to the TDU's measures in its resiliency plan under §25.62. REP Coalition commented that historically the amount of leased TEEEF capacity has varied widely depending on how each TDU plans to deploy such facilities during a significant power outage. REP Coalition noted that, as TDUs begin to implement their resiliency plans, the use cases and deployment procedures for TEEEF could change. OPUC agreed with REP Coalition that TEEEF applications should include the use cases intended for each TEEEF. OPUC explained that such questions do not need to be challenging, but TDUs should be able to provide concise and thorough answers to justify TEEEF usage and investment.

TCPA recommended that proposed §25.56(c)(1)(A) be revised to require the commission to consider the applicant TDU's investments in resiliency or, if applicable, the TDU's resiliency plan, when reviewing a TEEEF application. TCPA also recommended a TDU be required "to characterize the probability of reoccurrence of historical service interruptions." TCPA provided redlines consistent with its recommendation.

Commission Response

The commission reviews the specific criteria submitted by commenters for the commission approval of TEEEF capacity under the header for Question 2. Generally, the commission has included requirements identical or similar to those recommended by the above commenters. The exception to this is details surrounding the cost of TEEEF and the particulars of TEEEF leases. The commission's preapproval process is intended to take place before the TDU enters into leases for TEEEF, making these details unavailable during this proceeding. However, even if a TDU receives authorization to lease TEEEF, it must still lease and operate its TEEEF prudently, and any TEEEF costs not prudently incurred will be subject to reconciliation at the TDU's next base-rate case.

TNMP commented that if the commission retains the pre-approval process as a requirement, then proposed §25.56(c)(1)(A) should be revised to require "an explanation of "relevant factors supporting the reasonableness and necessity of the amount of TEEEF generating capacity requested." TNMP explained that the proposed term "all factors" could be construed to mean that a factor weighs against approval because a TDU chose not to include or highlight it in its application. TNMP emphasized that a TDU should be able to choose the most relevant or substantive factors without establishing a negative inference if a TDU does not include or provide more information for a given factor.

Commission Response

The commission declines to implement the recommended change because it is moot. The adopted rule language does not include the commented-upon provision.

Proposed §25.56(c)(2) - TEEEF application proceeding

Proposed §25.56(c)(2) establishes the timeline on which contested case proceedings under §25.56(c) will proceed. Additionally, proposed §25.56(c)(2) establishes that the commission will issue an order on reasonableness and necessity of a TDU's application and include an eligible lease term for approved TEEEF generating capacity.

OPUC recommended proposed §25.56(c)(2) be revised to clearly state "any maximum duration limitations on TEEEF leases should either be stated in rule and uniformly applied or left to private market forces on a case-by-case basis."

Commission Response

The commission declines to implement the recommended change. Under §25.56(c)(3) of the adopted rule, the commission's evaluation and final determination must include the expiry date or dates for the capacity of TEEEF a TDU is authorized to lease. By requiring the final order to prescribe the length of authorization, the commission has the flexibility to consider future measures that may mitigate the need for TEEEF, such as the competition of a TDU's resiliency plan under §25.62. This flexibility allows the commission to both consider the present needs of each TDU and limit the amount of costs past through to ratepayers for unnecessary TEEEF.

Oncor and AEP recommended the commission provide more specific timelines for the application review process under proposed §25.56(c)(2) and requested the commission consider whether the timeline could be further expedited. Oncor expressed concern with the length of the review process under proposed §25.56(c)(2). Specifically, the 120-day review period for commission staff to make a recommendation on the reasonableness and necessity of the requested amount of TEEEF capacity. AEP recommended all deadlines be shortened and specifically recommended the timeline for processing a TEEEF application be reduced from 120 days to 60 days. AEP stated that, as proposed, the timeline for a TEEEF proceeding is close to the statutory deadlines for a comprehensive base-rate case, which is unnecessary given that the application only concerns the amount of TEEEF generating capacity.

Oncor commented that proposed §25.56(c)(2)(B)(ii) is ambiguous and could lead to a longer commission staff review period than 120 days. Oncor noted that the provision requires commission staff to file a recommendation within 120 days of the TDU filing an administratively complete application. Oncor explained that if an application is deemed to be administratively incomplete, then the 120-day period would not begin until the date the TDU filed a corrected application that is then deemed to be administratively complete. Oncor noted that an alternative interpretation of the provision is that Staff has 120 days to files its recommendation plus the 42 days the presiding officer has to determine whether the application is administratively complete for a total of up to 162 days from the date of filing. Similarly, AEP recommended proposed §25.56(c)(2)(C) include a deadline for the commission to issue an order under. AEP explained that adding a deadline for the commission to issue an order will help ensure such proceedings are processed efficiently and the applicant TDU has certainty for contracting and RFP purposes.

REP Coalition recommended revising proposed subsection (c)(2) and (c)(2)(C) to ensure determinations of administrative completeness are made expeditiously. Specifically, REP Coalition recommended proposed §25.56(c)(2) be revised to specify the criteria for an application to be determined as administratively sufficient such as including the information required under subsection (c) and proof that the TDU has provided the required notice. The REP Coalition also recommended that the commission remove the 120-deadline for a staff recommendation and advised that the proceeding should proceed according to a docket-specific procedural schedule. REP Coalition provided draft language consistent with its recommendation.

Commission Response

The commission agrees with the general sentiment that the rule should contain more structure around the sufficiency determination and that 120 days is too long for staff to provide its final recommendation - especially since this recommendation traditionally occurs before a contested case. The commission also agrees with the REP Coalition that the majority of the proceeding should occur according to a docket-specific timeline. Accordingly, the commission adds more structure to the timeline prior to the contested case, but provides discretion to the presiding officer to determine the appropriate timeline for the remainder of the proceeding.

TNMP recommended revising proposed §25.56(c)(2) to expressly indicate that parties to a TEEEF pre-approval proceeding for generating capacity are not entitled to a hearing on the merits. TNMP explained that the 120-day deadline and the lack of reference to a hearing or discovery supports this conclusion. TNMP further noted that the commission recently determined that parties to a Distribution Cost Recovery Factor (DCRF) proceeding are not entitled to a hearing because a DCRF is an expedited proceeding, and that the same rationale should apply to TEEEF pre-approvals. OPUC and REP Coalition disagreed with TNMP that the pre-approval process not include a hearing on the merits. Specifically, OPUC opposed TNMP's contention that the pre-approval process should be "quick and shallow," with no right by a party to fully contest an application or have a hearing on the merits.

OPUC commented that recent legislative hearings regarding TEEEF highlight the importance of a thorough and holistic pre-approval process that reviews more than just capacity and highly detailed after-action reporting. OPUC stated that its assumption is that the pre-approval process would occur prior to an RFP process so that the TDU may review customer needs and the received proposals. Accordingly, OPUC contended that it is not impractical for TDUs to develop leases that take into account the pre-approval and review by the commission. OPUC further commented that it is unpersuaded that potential risk premiums, which may add to the total cost of a TEEEF lease, outweigh the benefits of ensuring appropriate regulatory oversight. OPUC noted that "Purchased Power Agreements" generally condition contract execution on commission approval and that TEEEF leases could be similarly drafted. OPUC averred that emergency TEEEF procurements could be streamlined into a standardized form with the option to submit additional information as necessary. OPUC commented that the timelines posited by the proposed rule are not burdensome and that TDU's should be able to plan accordingly for potentially future emergency events next calendar year.

REP Coalition explained that a hearing on the merit would provide an opportunity for parties to review and test the details of a TEEEF procurement and allows the commission to assess all relevant facts and evidence before imposing costs on ratepayers. REP Coalition averred that without a hearing on the merits, the pre-approval process would be rendered meaningless and only serves as a superficial approval based on a TDU's bare assertions. REP Coalition further noted that under the proposed rule TDUs can borrow TEEEF from other TDUs through mutual aid programs and engage in emergency procurement of TEEEF while litigation is ongoing.

Commission Response

The commission agrees with OPUC and REP Coalition that the commission approval of TEEEF capacity should include an opportunity for a hearing on the merits because it is a contested case. The commission does not agree with TNMP that a DCRF proceeding is an appropriate analogy for a TEEEF pre-approval proceeding. This proceeding is more akin to a resiliency plan or a certificate of convenience and necessity (CCN) proceeding for a new transmission line. Unlike a DCRF proceeding, which is expedited because its primary purpose is to allow TDUs to begin to recover for traditional utility expenses, CCNs, TEEEF, and resiliency plans each involve a TDU making a more significant investment that the commission needs to weigh in on to reduce the risk of high costs to ratepayers and to provide added security to TDUs to confidently make those investments.

TCPA and REP Coalition recommended adding notice and intervention deadlines under §25.56(c)(2). Specifically, TCPA recommended proposed §25.56(c)(2)(A) be revised to include specific notice and intervention provisions similar to those provided under §25.62 to indicate that third parties can participate in TEEEF proceedings. TCPA provided redlines consistent with its recommendation. Similarly, REP Coalition recommended new §25.56(c)(2)(C) be added to the rule to clarify that affected market participants such as REPs may intervene in TEEEF pre-approval dockets. REP Coalition noted that since proposed subsection (c) references a "contested case proceeding," this change would reduce potential ambiguity regarding who may intervene in a TEEEF pre-approval proceeding. REP Coalition emphasized the importance of market participants be allowed to participate in proceedings for initial approval of TEEEF capacity. REP Coalition provided draft language consistent with its recommendation.

Commission Response

The commission agrees with commenters and implements the recommended changes in §25.56(c). The commission also adds REP Coalition's recommended language which requires a TDU to provide notice of its filed application, including a deadline for intervention, to certain parties by the day after it files its application. The provision also specifies that the intervention deadline is 30 days from the date service of notice is complete.

AEP recommended that the language requiring commission review and pre-approval of the term length of a TEEEF lease be removed from the rule. AEP commented that the text of proposed subsection (c) suggests that commission review and pre-approval is limited to TEEEF capacity, however, proposed subsection (c)(2)(C) indicates that the commission will also review and approve the number of years a TDU is eligible to lease the requested TEEEF capacity. AEP explained that a TDU should retain flexibility in choosing lease terms because the term of a lease is a significant factor in the cost a TDU incurs. Alternatively, AEP recommended that if the commission retains the language regarding review and pre-approval of TEEEF lease term length, then proposed subsection (c) should be revised to explicitly indicate it.

HEN recommended that TEEEF contracts should include "periodized and standardized expiry dates through which market participants can competitively bid to provide those services." HEN explained that the standardization of regular expiration dates for TEEEF leases will permit "the continued refreshing of costs rather than saddling customers with lengthy and costly riders." HEN noted that any increased administrative costs associated with periodized contracting periods would be marginal relative to the cost savings of long-term leases. HEN further explained that any costs during higher-risk periods such as winter, summer, or hurricane seasons could be increased or decreased and accordingly allocated during an interim DCRF proceedings.

Commission Response

The commission agrees with AEP that TDUs should retain discretion over the length of individual lease terms. As described above, the commission modifies the rule to clarify that the commission's authorization applies to the TDU's TEEEF fleet, and not individual leases. The TDU has the flexibility as to the length of its leases, so long as the leases do not exceed the amount of time authorized by the commission.

Proposed §25.56(d) - Emergency Procurement of TEEEF

Proposed §25.56(d) authorizes a TDU to enter into a lease for TEEEF without going through a contested case proceeding under certain emergency circumstances, establishes that the amount of TEEEF generating capacity leased under this subsection must not significantly exceed the amount of megawatts necessary to restore electric service to its distribution customers, and requires a TDU to provide sufficient documentation during its next comprehensive base-rate proceeding to support the amount of TEEEF generating capacity leased under this subsection.

OPUC recommended that TDUs be "extremely limited" in utilizing emergency procurement of TEEEF under proposed §25.56(d). Specifically, OPUC recommended the rule limit TEEEF leases without prior approval for a term of three months or less. OPUC also recommended limiting the capacity to be leased during emergency procurement of TEEEF to not exceed the amount of energy necessary to restore service to the TDU's distribution customers and removing the term "significantly" from proposed §25.56(d). OPUC further recommended the capacity of TEEEF procured during an emergency be in an amount sufficient only to provide service during the significant power outage or the following power restoration process. OPUC explained that under its proposal, TDUs could still apply for standard TEEEF leases under proposed §25.56(c) without precluding emergency procurement when the need arises. OPUC commented that limiting emergency procurement in this manner would encourage more planning and preparation by requiring TDUs to justify emergency TEEEF procurements, including capacity and associated costs. Accordingly, such limits on emergency procurement would deliver cost savings to consumers for emergency procurements that are unnecessarily lengthy or provide excess capacity.

REP Coalition similarly recommended expanding proposed §25.56(d)(3) to account for the procurement of emergency TEEEF outside of the pre-approval process. Specifically, REP Coalition recommended amending the provision to ensure that a "TDU's initial request to recover costs associated with the emergency procurement be made only in a base-rate proceeding," therefore ensuring cost recovery is postponed until there is a full prudence review of the emergency TEEEF procurement. REP Coalition provided draft language consistent with its recommendation.

Commission Response

The commission declines to implement the recommended changes because they are impracticable. Artificially limiting emergency leasing of TEEEF under §25.56(d) would defeat the purpose of the provision to provide an opportunity to lease TEEEF in exigent circumstances when a TDUs determine it lacks sufficient capacity to restore power in accordance with §25.56(f). Moreover, arbitrary limitations on TEEEF capacity or lease terms for emergency procurement may have unintended consequences for when a TDU attempts to procure necessary additional capacity in a relatively short timeframe.

However, OPUC's concerns can be addressed in the TDU's next base-rate case. Any TEEEF capacity that is leased in an emergency will be subject to scrutiny, and any associated expenses will be subject to disallowance if the emergency lease was not reasonable, necessary, and prudent.

OCSC, REP Coalition, TNMP, CenterPoint, and TCPA requested clarification on what the term "must not significantly exceed" means in proposed §25.56(d)(2). OCSC recommended the provisions in proposed §25.56(d) regarding emergency TEEEF procurement be revised for clarity. Specifically, OCSC noted that the phrases "must not significantly exceed" and "(sufficient) documentation" are subjective and do not contain firm requirements. OCSC recommended that proposed §25.56(d)(2) be revised to set "a specific reasonable ceiling over the number of megawatts necessary to restore service." OCSC further recommended that the rule should list the specific documentation necessary for a TDU to support the emergency TEEEF procurement in the TDU's next comprehensive base-rate proceeding. REP Coalition noted that under proposed §25.56(d)(2), the term "significantly" is vague as used in the phrase "must not significantly exceed the amount of megawatts necessary to restore electric service to the TDU's distribution customers." REP Coalition explained that usage of the ambiguous term is overly permissive in allowing TDU to procure additional TEEEF that has not been subject to commission approval. REP Coalition recommended revising the rule such that the emergency lease cannot exceed the amount necessary to restore power "by more than a reasonable amount." REP Coalition also recommended adding that in determining reasonableness the commission may consider other emergency leases.

TNMP recommended revising proposed §25.56(d)(2) to clarify the term "significantly exceed." Specifically, TNMP noted that what it means to significantly exceed the amount of pre-approved TEEEF is unclear and could lead to inconsistent results and would not be foreseeable to TDUs other than in hindsight. TCPA similarly recommended deleting the term "significantly" from the phrase "may not significantly exceed" and instead require that capacity be correctly sized. TCPA explained that TDUs have had significant time using TEEEF prior to this rulemaking, and therefore the circumstances where emergency procurement is necessary should be low and have a higher threshold for approval with the commission.

TCPA also recommended that TEEEF procured in an emergency not be eligible for extension or renewal without prior commission approval. TCPA provided redlines consistent with its recommendation.

Commission Response

The commission revises the rule by replacing the term "significantly" from §25.56(d)(2) and appending "by more than a reasonable amount" to the provision as recommended by REP Coalition. However, the commission does add REP Coalition's additional language that the commission may consider other emergency leases when evaluating reasonableness. The TDU carries the burden to prove that it acquired a reasonable amount of emergency TEEEF capacity, and the commission may consider any appropriate evidence in evaluating its claim in the next base-rate case. For the same reason, the commission declines to list specific documentation that must be provided, as recommended by OCSC.

The commission declines to modify the rule to create a "reasonable ceiling" or require correct sizing as recommended by OCSC and TCPA, respectively. Precisely sizing a TEEEF unit to what is required to restore power during a particular outage is an unreasonably high standard to meet. Further, what constitutes a "reasonably ceiling" will vary based on the nature of the outage and the types of units available at that time. Instead, the commission expects TDUs to make reasonable decisions about when an emergency TEEEF lease is appropriate and what type of TEEEF it should lease. As stated above, the TDU's decisions will be reviewed for prudence, and any imprudently incurred costs associated with an emergency TEEEF lease will be subject to disallowance.

The commission also declines to prohibit extensions of emergency leases without commission preapproval, because it is unnecessary. All lease extensions, emergency or otherwise, must go through the preapproval process.

Proposed §25.56(e) - Competitive bidding process

Proposed §25.56(e) requires that a TDU use a competitive bidding process when seeking to lease TEEEF, and, if a competitive bidding process was not reasonably practicable, demonstrate in related cost recovery proceedings that a competitive bidding process was not reasonably practicable. Additionally, proposed §25.56(e) establishes that the commission may consider whether contracts a TDU entered into for TEEEF were reasonable compared to other available contracts when reviewing the reasonableness or necessity of costs associated with leasing TEEEF in a cost recovery proceeding.

OPUC emphasized that the competitive bidding process should be reviewed by the commission to ensure that "requests for proposals are robust and the solicitations are tailored to attract the type, magnitude, and scope of the outage targeted by the TDU."

Commission Response

The commission declines to implement the requested change because it is impracticable. A TDU should retain discretion when procuring TEEEF due to the limited availability and difficulty associated with leasing such units. OPUC's concerns regarding the competitive bidding process are substantially addressed by the authorization for the commission to review the reasonableness of TEEEF contracts a TDU executed under §25.56(e)(1). Moreover, this provision is consistent with PURA §39.918(f), which requires a TDU to use a competitive bidding process to lease TEEEF "when reasonably practicable."

Oncor recommended proposed §25.56(e)(1) be qualified with term "if any" to reflect that, in some cases, only one vendor or supplier may be available to lease TEEEF needed by a TDU at that time. Oncor commented that such a change would be consistent with proposed §25.56(e)(2) which acknowledges the possibility that a competitive bidding process may not be reasonably practical in certain situations. Oncor provided draft language consistent with its recommendation.

REP Coalition recommended that, if Oncor's proposed change is implemented, the rule should be clear that it does not apply to affiliate transactions and that a TDU bears the burden of proof to show that the competitive bidding process was impractical. In response to Oncor's comments regarding proposed §25.56(e)(1), REP Coalition contended that a competitive bidding process should provide evidence that such supplier limitations exist.

TCPA and the REP Coalition recommended that proposed §25.56(e) be revised to explicitly require a competitive bidding process for all TEEEF leases outside of emergency TEEEF leases under proposed §25.56(d). REP Coalition also recommended revising proposed §25.56(e)(2) to prohibit TDUs from entering into TEEEF leases with competitive affiliates unless a competitive bidding process is used.

Commission Response

The commission agrees with Oncor that there may not always be multiple bids for the commission to compare when assessing the prudence of a bid, and modifies the rule accordingly.

The commission also agrees with TCPA and REP Coalition and revises §25.56(e) to require a competitive bidding process in all circumstances outside of an emergency TEEEF lease under §25.56(d). By statute, a TDU is required to use a competitive bidding process "when reasonably practicable." In allowing for emergency TEEEF lease that do not require commission preapproval, the commission establishes a consistent regulatory framework that aligns with this statutory language and protects customers from unreasonable TEEEF-related costs associated with TEEEF. It most circumstances, the TDU must first obtain commission authorization for the amount of TEEEF it is requesting to lease, to ensure the TDU does not have an oversized TEEEF fleet, and it must use a competitive bidding process to ensure it is able to lease that fleet at reasonable cost. However, in the context of an imminent or ongoing significant power outage, neither a preapproval process nor a competitive bidding process are practicable. Accordingly, the adopted rule provides a limited exception to both processes during emergencies.

The commission also shares the REP Coalition's concerns regarding a TDU leasing of TEEEF from competitive affiliates. To ensure that these transactions are arms length, the commission modifies the rule to require a competitive bidding process for all TEEEF leases with competitive affiliates. The commission also notes that §25.273, relating to Contracts Between Electric Utilities and Their Competitive Affiliates is applicable to §25.56.

Finally, the commission adds a new paragraph to this subsection to require a TDU to allow for the inspection of its leases, if requested by a commissioner or commission staff. The new paragraph also requires the commissioner or commission staff to treat any retained copies of the lease as confidential if requested by the TDU. If a request is made under the Public Information Act for the commission to produce any retained leases provided under this paragraph, the commission will notify and provide the TDU with an opportunity to assert its claim of confidentiality under Texas Government Code Chapter 552 (Public Information Act).

AEP recommended that proposed §25.56(e)(1) be revised by replacing the second use of the term "contracts" with the more broadly applicable term "bids." AEP commented that it is unlikely that a TDU will have multiple contracts available as part of the competitive bidding process and therefore the language in proposed §25.56(e)(1) is imprecise. AEP explained that when engaging in the competitive bidding process, a TDU may have multiple bids, proposals, or offers and that a contract is only drafted after one is selected. AEP provided draft language consistent with its recommendation.

Commission Response

The commission agrees with AEP and revises the provision to state that the commission may also consider whether the contracts the TDU entered into to lease TEEEF were reasonable relative to other bids that were available to the TDU.

Proposed §25.56(f) and (f)(1) - Deployment of TEEEF

Proposed §25.56(f) establishes the criterion for when and how a TDU may deploy a TEEEF, including authorized use cases and notice, coordination, billing, and after-action reporting requirements. Additionally, proposed §25.56(f) establishes how an operator of an affected generator or load resource should coordinate with ERCOT during a TDU's TEEEF deployment. Proposed §25.56(f)(1) establishes the criteria under which a TDU may deploy TEEEF to aid in restoring power to its distribution customers during an event that a TDU reasonably determines is a significant power outage.

Oncor requested proposed §25.56(f)(1) be revised for clarity because the proposed language implies that "TEEEF may not be deployed to neighboring TDU service territories in accordance with mutual aid arrangements." Oncor commented that this restriction is not beneficial to end-use customers in an emergency.

Commission Response

The commission agrees with Oncor but declines to revise §25.56(f)(1) as recommended because the proposed language of that provision directly reflects the criteria stipulated by PURA §39.918(b)(1)(A) and (B). Instead, the commission adds new §25.56(f)(2) to reflect that TEEEF loaned or utilized in accordance with a mutual assistance agreement or program is an acceptable usage of TEEEF provided that all costs and revenues associated with such a loan or utilization are properly accounted for and reconciled. The commission renumbers the rest of the subsection accordingly.

Oncor recommended adding language to proposed §25.56(f)(1)(B) that would authorize usage of TEEEF when a TDU's distribution facilities are not being fully served by the bulk power system during normal operations due to issues with the transmission or distribution system. Oncor requested further clarification on what is meant when "the TDU's distribution facilities are not being fully served by the bulk power system" in proposed §25.56(f)(1)(B). Oncor noted that, while the same language is used under PURA §39.918(b)(1)(B), there is ambiguity as to whether the provision authorizes a TDU to deploy TEEEF when distribution facilities are not being fully served by the transmission system due to mis-operation, damage, or any other issues solely on the transmission system, or whether the provision otherwise permits TEEEF deployment if issues arise on either the distribution or transmission system. Oncor commented that in a prior review of a TDU's TEEEF deployment, the commission authorized usage of TEEEF when damage to the TDU's distribution system were not caused by issues with the bulk power system and that such a deployment was compliant with PURA §39.918(b). Oncor provided draft language consistent with its recommendation.

Commission Response

The commission declines to implement the requested change because it is unnecessary. A TDU's "distribution facilities" extend to all facilities on the distribution system up to a retail customer's meter. Any interruption in electric service to a portion of a TDU's distribution facilities that constitutes a "significant power outage" results in the TDU's distribution facilities not being fully served by the bulk power system. Neither PURA §39.918 nor the rule require the cause of the outage to be located on the transmission system.

AEP recommended proposed §25.56(f)(1) be revised to apply to TEEEF "energization" rather than "deployment" since there is a meaningful difference between the two terms. AEP noted that deployment begins with making an initial request to the vendor and then potentially transporting TEEEF facilities to the affected location which could take up to 23 hours. AEP further commented that deployments may also occur prior to an anticipated significant power outage. In contrast, AEP noted that energization is the last stage of a TEEEF deployment and, in some cases, deployment of TEEEF does not necessarily lead to energization. Similarly, if the commission retains the requirement for TDUs to submit after-action reports under proposed §25.56(f)(9), AEP recommended the term "deployments" be changed to "energization" in §25.56(f)(9) and §25.56(f)(9)(A) so that after-action reports are only required after TEEEF energizations. AEP provided draft language consistent with its recommendation.

Commission Response

The commission agrees with AEP's recommendation to replace "deployment" with "energization" and respectively replaces all instances of the term "deployment" and "deploy" with the terms "energization" and "energize" accordingly.

Additionally, the commission modifies §25.56(f)(10) to require a TDU to submit an after-action report to the commission after each instance of significant power outage in which the criteria for TEEEF energization under §25.56(f)(1) is met.

OPUC recommended proposed §25.56(f)(1) be revised to authorize a TDU to deploy TEEEF during a "significant power outage," if the commission adopts OPUC's proposed revisions to the "significant power outage" definition. OPUC explained that, under its proposed revisions, a TDU would no longer have the discretion to determine when a "significant power outage" occurs and, instead, whenever a TDU is ordered to shed load would qualify as a "significant power outage." OPUC noted that in all other outages, such as those of a certain duration, or that affect a certain number or type of customers, or that otherwise pose a risk to public health and safety would be determined by the TDU.

Commission Response

The commission declines to implement OPUC's recommended change because it is unnecessary. Specifically, the commission has declined to implement OPUC's previous recommendation for the definition of "significant power outage" under §25.56(b), rendering its recommendation for §25.56(f)(1) moot.

TCPA and REP Coalition objected to language in proposed §25.56(f)(1) that would authorize a TDU to pre-emptively deploy TEEEF on the basis that it is contrary to statute. TCPA recommended proposed §25.56(f) be revised to "not give discretion to the TDU to determine when a significant power outage has occurred" because the statutory definitions are clear and objective. TCPA commented that certain provisions of §25.56(f)(4) are inconsistent with PURA §39.918 because it contemplates pre-deployment of TEEEF and proactive disconnection of parts of the distribution system that are using TEEEF. TCPA explained that the definition of "significant power outage" is purely retrospective and that TEEEF deployments are meant to aid in restoring power during a significant power outage. Therefore, any rule language that contemplates pre-emptive TEEEF deployment is impermissible and out of scope.

REP Coalition recommended proposed §25.56(f)(1) and several sub-provisions be revised such that the standard for commission review of TEEEF deployments is more consistent with PURA §39.918(b)(2) and does not authorize a TDU to take pre-emptive action. Specifically, REP Coalition recommended the provision be revised to require that the review be based on evidence indicating either that ERCOT has directed the TDU to shed load or the TDU's distribution facilities are not being fully served by the bulk power system under normal operations. REP Coalition stated that, as proposed, the rule merely requires the TDU reasonably determine that the prerequisites occurred. REP Coalition noted that the two scenarios contemplated by PURA §39.918(b)(1) are limited to "aid in restoring power" and neither scenario "(is) subjective or prospective such that they would authorize the TDU to pre-emptively isolate a portion of its distribution system from the bulk power system."

Commission Response

The commission declines to implement the recommended change because it is unnecessary. The replacement of the terms "deployment" and "deploy" with the terms "energization" and "energize" are intended to clarify the ambiguity that may be associated with the conflation of those terms.

The commission also declines to modify the rule to remove the language that a TDU may energize TEEEF when it reasonably determines that a significant power outage has occurred. The commission does not agree with commenters that the use cases for TEEEF are "clear and objective" such that they do not require the exercise of judgment. For example, what constitutes a significant number of distribution customers, how long an outage is expected to last, and whether a risk to public health and safety is created due to an outage effecting a critical facility all require some measure of judgment, and the TDU is the entity best positioned to exercise that judgment with regards to its own system in real time.

Proposed §25.56(f)(4) - Notice

Proposed §25.56(f)(4) requires a TDU to notify the independent organization certified under PURA §39.151 for the ERCOT region and all operators of affected generators or load resource at least 10 minutes prior to an affected area's isolation from, and reconnection to, the bulk power system, and immediately after the reconnection has been completed.

Oncor recommended proposed §25.56(f)(4) be revised to exempt TDUs from the notice requirements when the significant power outage was outside of the TDU's control or when the TDU deploys less than 10 MW of TEEEF capacity. Oncor expressed concern with the time periods for notification of ERCOT and all operators of affected generators or load resources (i.e.g ten minutes before isolation and reconnection, and immediately upon isolation and reconnection). Oncor commented that such notifications could hinder power restoration efforts because the notices would have to be sent during an emergency when a TDU's employees are otherwise preoccupied. Oncor also questioned the benefit of providing multiple notices to ERCOT or ERCOT's dispatch analysis. Oncor provided draft language consistent with its recommendation.

ERCOT recommended that an exception for "circumstances beyond a TDU's control" be added to the notice required at least ten minutes prior to the isolation of an affected area and the notice immediately following isolation of the affected area to be "as soon as reasonably practicable" rather than ten minutes. ERCOT commented that, where "an area is already disconnected from the bulk power system by circumstances beyond the TDU's control," the TDU could not reasonably anticipate that outage and likely would not be able to comply with the ten-minutes-prior notice requirement. ERCOT emphasized the importance of such notices being eventually received despite being on a varying time frame to ensure affected generators and load resources are not dispatched and are not receiving payment via ERCOT settlement for any energy generated while the area is isolated.

CenterPoint recommended revising proposed §25.56(f)(4) to account for circumstances where a TDU is unable to provide advance notice to ERCOT due to "personnel and resources being fully dedicated to outage restoration," changing conditions that may affect where and when TEEEF is deployed, and the potential lack of real-time visibility into affected generators and load resources. Specifically, CenterPoint recommended qualifying the provision to require that a TDU provide advance notice "to the extent practicable under the circumstances during a significant power outage." CenterPoint provided draft language consistent with its recommendation.

TNMP noted that compliance with proposed §25.56(f)(4) is problematic because TDUs "generally lack sufficient information required to contact generators or other load resources." AEP agreed with TNMP that it is unclear how a TDU would notify the listed entities in a widespread outage. TNMP also indicated that ERCOT would already be aware of lost load or would otherwise be instructing a TDU to shed load. TNMP explained that under typical load shed events a TDU does not inform ERCOT of how it is rolling circuits and that such a practice should be no different for TEEEF deployments. TNMP also contended that deployment of TEEEF should not incur additional requirements because ERCOT will either have ordered the load shed or the load will already have been lost prior to deployment and would therefore not impact the system. TNMP stated that applying notice requirements for some outages and not others depending on the TEEEF deployment is unnecessary and impractical during what may be an emergency.

Commission Response

The commission reorganizes the provision to clearly delineate between TDU notice requirements (i.e., "prior to isolation," "upon isolation," "prior to reconnection," and "upon reconnection") and to clearly separate the TDU notice requirements from the coordination requirements for both TDUs and operators of affected generators or load resources. Further, the commission relocates the description of "affected generators or load resources" in proposed §25.56(f)(4)(A) to new §25.56(b)(1).

The commission modifies the provision as requested by Oncor and ERCOT to differentiate between TDU notice requirements for when an isolation from the bulk power system is due to circumstances within a TDU's control and when an isolation is due to circumstances beyond a TDU's control. For isolations due to circumstances within a TDU's control, the notice requirements remain as proposed (i.e., 10 minutes prior to isolation and upon isolation). For isolations due to circumstances beyond a TDU's control, the commission revises the provision to require a TDU to notify ERCOT "as soon as is reasonably practicable."

The commission declines to modify the proposed rule as requested by CenterPoint because it is unnecessary. The modification described above adequately addresses CenterPoint's concern by providing flexibility around the notice requirements to TDUs when isolations from the bulk power system are due to circumstances beyond a TDU's control.

The commission disagrees with TNMP and AEP and, accordingly, declines to modify the proposed rule to remove entirely the requirement for TDUs to issue notice of TEEEF energization to ERCOT and operators of affected generators or load resources. These notices are imperative to ensuring that: (1) both ERCOT and operators of affected generators or load resources are aware that a TEEEF energization will impact their operations and settlement processes, and (2) TEEEF is not included, or is otherwise removed, from ERCOT's locational marginal pricing calculations, wholesale market pricing, and reliability models as required by PURA §39.918(d)(2).

However, the commission modifies the provision to provide that TDUs must only issue notice to ERCOT and operators of affected generators or load resources when TEEEF is energized in an area isolated from the bulk power system that contains an affected generator or load resource. This modification will ensure that the notice requirements under this subsection are balanced to the practical and operational reality of power restoration during significant power outages. Both ERCOT and operators of affected generators and load resources will still receive notice from TDUs when an energization of TEEEF may impact their operations or settlement processes, but neither the TDUs, nor ERCOT, nor the operators of affected generators or load resources will be hampered by issuing or receiving notice of TEEEF energization when unnecessary.

Proposed §25.56(f)(4)(B)(iv) - Statement of non-settlement

Proposed §25.56(f)(4)(B)(iv) requires a TDU's notice to the independent organization and to affected generators or load resources regarding isolation and reconnection to include a statement that any energy produced by an affected generator during the time it is isolated from the bulk power will not be settled through the independent organization.

TEC recommended that a generator that continues to serve load within an isolation portion of the system should recover the costs to produce power even in isolation. TEC commented that proposed §25.56(f)(4)(B)(vi) is ambiguous because it states that energy produced by an affected generator will not be settled through ERCOT. TEC explained that it is therefore unclear as to whether an affected generator may continue to operate in isolation or at all. TEC also recommended the commission consider the reliability tradeoffs when isolating a larger generator in exchange for operating what may be a smaller capacity TEEEF.

Commission Response

The commission declines to implement the requested change because it is not feasible. Under adopted §25.56(f)(8)(B), an affected generator that operates in isolation from the bulk power system will not be settled by ERCOT. This provision does not prohibit an affected generator from operating in an island being energized by TEEEF, but instead reflects the practical reality that energy generated within such an island will not reach the bulk power system and, therefore, will not be settled by ERCOT.

Calpine recommended that, in addition to the requirement under proposed §25.56(f)(3)(B), a provision be added that requires ERCOT to develop Protocols that would "codify and implement more detailed mechanisms and protections" to ensure the requirements of proposed §25.56 are reflected in the applicable ERCOT market rules and be effective as soon as possible. Calpine commented that there is the potential for TEEEF to reduce the amount of dispatched generation which would then impact load shed prices. Calpine noted that there is no requirement in the ERCOT Protocols to incorporate "the load that would have been served by the bulk power system but-for the localized load shed instruction" into the Reliability Deployment Price Adder (RDPA). Calpine explained that such load should be included in the RDPA during a system-wide emergency because it would be consistent with its intent to mitigate price distortions that result from out-of-market actions, such as load-shed events, which trigger TEEEF deployment. Calpine emphasized that PURA §39.918(d)(2) prohibits TEEEF from being included in locational marginal pricing calculations, prices, or reliability models. Accordingly, Calpine commented that the rule require the establishment of ERCOT Protocols that would prevent TEEEF deployment from having an impact on pricing during a localized load shed event. Calpine provided draft language consistent with its recommendation.

Commission Response

The commission declines to explicitly require ERCOT to develop rules or procedures to ensure TEEEF are not included in locational marginal pricing calculations, pricing, or reliability models consistent with the requirements in adopted §25.56(f)(4)(B). TEEEF are not currently included in ERCOT's Network Operations Model and therefore will not be dispatched or be directly incorporated into locational marginal prices or pricing models.

Proposed §25.56(f)(4)(E) - Coordination with independent organization

Proposed §25.56(f)(4)(E) requires a TDU to, where the isolation of load from the bulk power system is due to circumstances beyond the TDU's control, coordinate the isolation or reconnection of load associated with TEEEF energization that occurs outside of any energy emergency declared by the independent organization certified under PURA §39.151 if the total amount of load at a single substation that would be isolated or reconnected within a period of 10 minutes exceeds 20 megawatts. Proposed §25.56(f)(4)(E) also requires a TDU to notify operators of affected generators and load resources of any delay in the anticipated time of isolation or reconnection if the TDU has provided notice of an anticipated isolation or reconnection under §25.56(f)(4).

AEP recommended that proposed §25.56(f)(4) and proposed §25.56(f)(4)(E) be revised to account for scenarios where only a TDU's distribution system is impacted. Specifically, AEP recommended that the provisions be amended to not require notice be provided to "all operators of affected generators or load resources" in such situations because affected customers are not connected to the grid and therefore energization of the affected facilities would not impact the bulk electric grid. AEP commented that without this change, the notice requirement could be burdensome and time-consuming for a TDU and would result in an extension of the outage.

Commission Response

The commission declines to modify the proposed rule as requested by AEP. Notice to affected generators or load resources is necessary to make those entities aware that they are now operating within an islanded portion of the bulk power system. Consequently, those entities will not be compensated because the energy they generate will not be settled by ERCOT.

OPUC suggested that revising proposed §25.56(f)(4)(E) to require coordination with ERCOT when, relative to TEEEF energization, isolation of load from the bulk power system occurs. OPUC commented that such communication may take different forms depending on the circumstance or could occur even after the deployment of TEEEF.

ERCOT commented that a TDU's coordination with ERCOT is not required for the disconnection or reconnection of loads equal to or less than 20 MW because such load is "anticipated to be sufficiently immaterial that ERCOT can balance the system using existing tools at its disposal without the need for coordination between the TDU and the ERCOT control room." ERCOT further commented that, to prevent an overwhelming number of calls to the ERCOT control center, such coordination is also not necessary during an Energy Emergency Alert. ERCOT commented that coordination between a TDU and ERCOT is only important during events that involve large amounts of load being disconnected or reconnected to the bulk power system in a short timeframe. ERCOT further remarked that outages occurring during an Energy Emergency Alert should be excluded from the coordination requirements to prevent the control room from being overwhelmed by coordination calls if numerous outages occur at once.

Commission Response

The commission declines to modify the proposed rule as recommended by OPUC because it is unnecessary and unduly burdensome. As proposed, the rule provides for TDUs to coordinate with ERCOT when there is an isolation or reconnection of load from the bulk power system, within the TDUs' control, associated with TEEEF energization in an amount greater than 20 MWs at a single substation. The proposed rule intentionally limits coordination between TDUs and ERCOT to larger amounts (20MWs or greater) at a single location in order to provide ERCOT control room staff with the information needed to ensure that isolations or reconnections of load associated with TEEEF energizations do not jeopardize the reliability of the bulk power system. OPUC's recommendation, in contrast, would require TDUs to coordinate with ERCOT on every isolation of load from the bulk power system associated with TEEEF energization, which would increase the burden on ERCOT control room staff over an amount of load that would not otherwise pose a reliability risk.

Proposed §25.56(f)(4)-(7) - Isolation of affected area from the bulk power system

Proposed §25.56(f)(5) provides telemetry and operating plan requirements for operators of affected generators or load resources that are required by ERCOT protocols to provide status telemetry to ERCOT and that receives notice from a TDU that an area served by TEEEF will be disconnected from the bulk power system. Proposed §25.56(f)(6) establishes that a TDU's liability relating to the provision of service using TEEEF is governed by §25.214, relating to Terms and Conditions of Retail Delivery Service Provided by Investor-Owned Transmission and Distribution Utilities. Proposed §25.56(f)(7)(A) and (B) require a TDU to ensure, to the extent reasonably practicable, that a retail distribution customer' s usage during the TDU's operation of a TEEEF is excluded from the electric usage reported to the independent organization certified under PURA §39.151 for the ERCOT region for settlement and to retail electric providers (REPs) for customer billing and that energy generated in an area isolated from the bulk power system during operation of the TEEEF, including any energy generated by an affected generator, is excluded from the generation reported to the independent organization.

TEC requested clarity on proposed §25.56(f)(4)-(7) which relate to the isolation of portions of a TDU's distribution system when deploying TEEEF. TEC commented that such disconnections could negatively affect transmission and generation facilities owned by electric cooperatives connected to the grid by an affected circuit. TEC expressed concern that removing generation from service to operate TEEEF could "adversely affect system reliability, have local reliability implications, and harm the economics of the generator isolated from the market by action of the TDU." TEC recommended that operation of TEEEF be conducted in such a manner that non-TDU systems are not negatively affected. TEC noted that PURA §39.918(d)(1) only requires TEEEF to be operated in a manner such that it does not impact the wholesale market or reliability. TEC stated that, in contrast, PURA does not specifically contemplate "isolation that impacts and removes other systems or generators from service" and that isolated operations may amount to discriminatory treatment towards affected electric cooperatives or MOUs that are forced offline by TEEEF. Specifically, forcing members of an electric cooperative, or customers of a municipally owned utility (MOU), offline for the benefit of TDU consumers receiving power generated by TEEEF. TEC also commented that the isolation process is left ambiguous in the proposed rule. TEC specifically noted that the rule is unclear whether ERCOT or the TDU will maintain operational control of the isolated area or be responsible for monitoring technical limitations of the isolated system to ensure equipment is not damaged. TEC further noted that is not clear whether ERCOT or the TDU entity is liable if such damage does occur, as the proposed rule only references §25.214, which only concerns liability relating to competitive retailers, not electric cooperatives or other providers of generation.

TEC also recommended that the rule clearly state that transmission assets may not be taken offline to accommodate TEEEF. TEC expressed concern regarding any action that would involve "segmentation or the removal of transmission facilities from service" to accommodate TEEEF and opposed any action on this basis. TEC noted that PURA §39.918(b) expressly contemplates TEEEF being used for the benefit of distribution customers and accordingly, any action that removes transmission facilities from service would be contrary to the statutory intent.

Commission Response

The commission declines to modify the rule as requested by TEC because it is unnecessary. While the rule does make allowances for affected generator or load resources that are isolated from the grid, it is unclear the manner in which TEEEF would negatively impact transmission or generation facilities owned by a MOU or electric cooperative, or otherwise cause such facilities to be taken offline. The rule also includes protections to ensure the bulk power system and wholesale electric market are unaffected by TEEEF operation. Specifically, under adopted §25.56(f)(4)(A) and (B), TEEEF is required to be isolated from the bulk power system and not be included in ERCOT's locational marginal pricing calculations, pricing, or reliability models. Moreover, as noted by LCRA in its comments, there may be instances in which it may be able to use TEEEF to assist with the restoration of smaller MOUs or electric cooperatives for which LCRA serves as a transmission provider.

Oncor recommended proposed §25.56(f)(7)(A) be revised to reflect the practical limitations of TDU's systems when zeroing out energy usage of TEEEF. Oncor explained that while the provision requires a TDU to exclude TEEEF usage from being reported to ERCOT for settlement and to REPs for customer billing, in practice a TDU's meters automatically will record TEEEF usage as if the meters were connected to the grid. Oncor noted that a TDU cannot stop its meters from recording TEEEF usage initially. Instead, the TDU zeroes out the TEEEF's energy usage and provides this data to ERCOT on or before final settlement. Oncor provided redlines consistent with its recommendation.

ERCOT commented that currently TDUs have processes to remove customer electric usage and generation while the TDU's service area is isolated from the bulk power system before customer usage and generation data is transmitted to ERCOT for settlement. Accordingly, ERCOT anticipated that further action is unnecessary beyond those existing TDU processes to ensure that retail customers are not billed for usage, and affected generators are not paid for generation, while TEEEF is operational. However, ERCOT noted that internal changes are necessary for generation data reported to ERCOT by resources with an ERCOT Polled Settlement meter and are within an isolated area to ensure such generation is excluded from settlement.

Commission Response

The commission agrees with Oncor and implements the following change to adopted §25.56(f)(8)(B): "a retail distribution customer's usage during the TDU's operation of a TEEEF is excluded or removed from the electric usage reported to ERCOT for final settlement and to the retail electric providers (REPs) for customer billing." The commission declines to add the term "ultimately" from the phrase "the electric usage reported to (ERCOT)" because the clarification regarding "final" settlement more concretely addresses Oncor's concern.

Oncor recommended that proposed §25.56(f)(7)(B) be revised for clarity by indicating that affected generators of any type, including distributed generation, should be excluded from the generation reported to ERCOT. Oncor noted the provision is otherwise unclear whether the provision is intended to exclude any energy, such as from rooftop solar or other distributed generation, from the generation data that the TDU sends to ERCOT during TEEEF deployments.

Commission Response

The commission declines to implement the recommended change because it is unnecessary. ERCOT maintains procedures for the registration of distributed generation in accordance with the ERCOT Protocols. If any distributed generation qualifies as an "affected generator" under adopted §25.56(b)(1)(A) and (B), then any power generated by such entities should be excluded from the generation reported to ERCOT for settlement purposes under §25.56(f)(7)(B).

AEP recommended that the requirement under proposed §25.56(f)(7)(B) to exclude any energy generated in an area isolated from the bulk power system during operation of the TEEEF, including any energy generated by an affected generator, from the generation reported to ERCOT for settlement purposes should be removed from the rule because it is out of scope of PURA §39.918. Alternatively, if the commission retains the provision, AEP recommended the inclusion of a grace period for compliance due to the additional IT investment necessary for such a function.

Commission Response

The commission declines to remove proposed §25.56(f)(7)(B) or include a grace period for compliance as recommended by AEP because the provision effectuates the intent of PURA §39.918(d)(2)(A)-(C) which prohibits TEEEF from being included in the independent system operator's locational marginal pricing calculations, pricing, or reliability models. The commission addresses AEP's concern by modifying adopted §25.56(f)(8)(B) to provide that "any energy generated by an affected generator"¦is excluded or removed from the generation reported to ERCOT for final settlement purposes." Additionally, the commission notes that TDUs must comply with adopted §25.56(f)(8) "to the extent reasonably practicable".

Proposed §25.56(f)(8) -Generation during EEA

Proposed §25.56(f)(8) requires the amount of any load shed by a TDU for the area operated in isolation from the bulk power system during operation of a TEEEF must be accounted for net of any generation in the affected area that was online and producing before the area was isolated from the bulk power system during an energy emergency declared by the independent organization.

Oncor recommended proposed §25.56(f)(8) be removed from the rule because it is unnecessary and redundant due to current TDU practices. Oncor explained that, when assessing the load of a feeder line shed by the TDU, the energy consumption from that line is already "net of generation that is delivering power onto that feeder," therefore "any load shed performed by a TDU will already be net of any generation that was delivering power onto the affected feeder." Oncor noted that if the provision remains in the rule, it may create uncertainty about the standard utility practice expected from TDUs.

Commission Response

The commission declines to remove adopted §25.56(f)(9) from the rule as requested by Oncor. Codification of an established utility practice in a commission rule will eliminate uncertainty as to what is expected from a TDU in that circumstance. And, as Oncor's comments suggest, if generation is already net of any generation that was delivering power onto the affected feeder, then compliance with this provision does not impose any burdens on the TDU.

Proposed §25.56(f)(9) - TEEEF deployment after-action report

Proposed §25.56(f)(9) requires TDUs to file an after-action report with the commission following all TEEEF deployments and establishes the information that TDUs must include in the report.

OPUC recommended the after-action report under proposed §25.56(f)(9) generally include the same information required in the application for commission approval of TEEEF generating capacity for standardized data points and accountability. OPUC also recommended the after-action report require TDUs to also report: the total system-wide outages; the number of TEEEF deployed and specific information relative to each TEEEF to correspond with the information in the respective applications; whether the TEEEF directly served residential load or other types of distribution-level customers or supported infrastructure instead; how the TDU used the TEEEF, including each location at which the TEEEF was stationed; critical facilities or customers served, if applicable, and amount of load, in MW, served by the TEEEF; and specifically within the area serviced by the TEEEF, the number of distribution-level customer outages. OPUC explained that this information would contextualize other information provided by the TDUs and help TDUs, stakeholders, and the commission to identify gaps in service during the emergency and opportunities for improvement in the future. OPUC also stated that the addition of these factors would improve accountability by ensuring that TDUs are using TEEEF as intended.

OPUC also recommended a commission-approved form be created for TEEEF applications for efficiency.

Commission Response

The commission agrees with OPUC that the criteria included in a TDU's application for commission approval of TEEEF capacity should be largely represented in a TDU's after-action report, and, where appropriate, aligns the provisions of each. Additionally, the commission adds additional details to the after-action report to help assess the TDUs' use of TEEEF for future preapproval proceedings and prudence reviews.

The commission declines to adopt a form for the pre-approval process at this time. The commission may adopt a form at a future time after it has more experience with TEEEF pre-approval proceedings.

Oncor recommended combining proposed §25.56(f)(9)(E) and (F) because the provisions significantly overlap. Oncor also recommended only requiring a TDU to report the number and type of critical load, critical care customers, or other critical infrastructure facilities impacted by a significant power outage and actually served by the TEEEF during that outage and any other details the commission deems necessary to include in the report.

Commission Response

The commission agrees with Oncor's formatting comments regarding §25.56(f)(10)(E) and (F) and restructures the provisions accordingly. Specifically, adopted §25.56(f)(10)(C) requires a TDU's after-action report to include, as applicable, the number and type of critical load, critical care customers, or other critical infrastructure facilities as defined by §25.497, that were affected by a significant power outage and the estimated number of which were served by TEEEF.

Oncor recommended that relocations of TEEEF units to a different default location should not trigger the after-action reporting obligation under proposed §25.56(f)(9). Oncor further requested the commission consider whether the act of sending TEEEF to another jurisdiction for mutual assistance purposes should be included in the term "deploy" and, if so, whether such an action triggers the requirement for a TDU to file an after-action report under proposed §25.56(f)(9). Oncor cautioned that defining "deploy" in the manner described by proposed subsection (b) could lead to interpretations of proposed §25.56(f)(1) as prohibiting TEEEF relocations outside of significant power outages that meet the criteria of proposed §25.56(f)(1)(A) and (B).

Commission Response

The commission declines to modify the rule to address whether movement of a TEEEF or sending TEEEF to another jurisdiction trigger the after-action report requirement. Instead, the commission modifies the proposed rule to require a TDU to file an after-action report with the commission when a significant power outage that meets the criteria for TEEEF energization occurs in the TDU's service territory. This modification will provide greater transparency around when TEEEF units are, or are not, utilized by TDUs during qualifying significant power outages.

Oncor, OPUC, TCPA, CenterPoint, and OCSC recommended proposed §25.56(f)(9) be revised to provide a filing deadline for after-action reports. Oncor, OPUC, and TCPA specifically recommended that proposed §25.56(f)(9) include a 30-day, or one month, deadline for submission of after-action reports, beginning on the day a significant power outage requiring TEEEF deployment has ended. Oncor cautioned that a TDU's ability to gather and submit the requisite information may be prevented by the significant power outage that required TEEEF deployment, therefore the rule should provide a sufficient amount of time to account for outages of a variable duration.

OPUC further recommended that TDU after-action reports submitted to the commission under §25.56(f)(9) be filed publicly. OCSC agreed that stakeholders should be provided timely access to such information.

Commission Response

The commission agrees with commenters and modifies the proposed rule to make after-action reports due 30 days from the date a significant power outage that qualifies for TEEEF energization has ended. These reports must be filed publicly on the commission's interchange.

OPUC recommended that explicit language be included in proposed §25.56(f)(9) to authorize the commission to use information submitted by a TDU as part of its after-action report as a basis for initiating a comprehensive base-rate case or investigation of costs under PURA Chapter 36, Subchapter D.

Commission Response

The commission declines to modify the proposed rule as requested by OPUC because it is unnecessary. The commission already has the authority to require electric utilities, including transmission and distribution utilities, to initiate a base-rate proceeding if the commission finds rates to be unreasonable under PURA §36.151.

Calpine recommended a new provision be added to the rule to ensure that market prices associated with a TEEEF deployment are consistent with PURA §39.918(d)(2). The new provision would authorize market participants to issue requests for information to ERCOT and the TDU submitting an after-action report if the information supplied by the TDU did not include adequate information to support a determination that wholesale prices during a TEEEF deployment met the requirements of proposed §25.56(f)(3)(B). The new provision would also require ERCOT and the TDU to respond to such requests within 30 days.

Commission Response

The commission declines to modify the proposed rule to add a new provision allowing market participants to issue requests for information regarding the impacts of TEEEF on wholesale market prices as requested by Calpine because the proposed provision does not align with the intent of the after-action reports. The after-action report is primarily designed to evaluate whether and how a TDU utilized TEEEF to restore power to distribution customers during a significant power outage. ERCOT is responsible for ensuring compliance with PURA §39.918(d)(2) and will develop any necessary protocols to ensure said compliance.

Proposed §25.56(g) - Emergency operations annex

Proposed §25.56(g) requires a TDU with leased TEEEF to include a detailed plan on the use of its leased TEEEF in its emergency operations plan filed with the commission. Additionally, proposed §25.56(g) requires that the TDU's plan for TEEEF provide detailed enough information for ERCOT to use the information for system restoration planning.

Oncor suggested proposed §25.56(g) be revised to require ERCOT to request that a TDU include a sufficient level of detail in its emergency operations annex for system restoration planning, rather than having the inclusion of such detail be an affirmative obligation of the TDU. Oncor stated that it currently includes TEEEF usage plans in its annual emergency operations plan filing and, given the ambiguity of the phrase "sufficient level of detail," it is unclear what additional information ERCOT could foreseeably need for system restoration planning purposes. Oncor expressed that it is willing to provide additional details if deemed necessary by ERCOT, and that its proposed change would accordingly authorize ERCOT to request such information on a case-by-case basis.

Similarly, AEP recommended revising proposed §25.56(g) to require coordination with ERCOT "as appropriate" for system restoration planning. AEP commented that it is unclear what level of detail an emergency operations plan's TEEEF annex must include to be sufficient for ERCOT system restoration planning purposes or even if it is possible to provide such information in advance given the mobility of TEEEF. AEP noted that, when mobilizing TEEEF within its service territory, it is not possible to provide ERCOT with a level of detail that would aid in "˜system restoration planning' at the bulk transmission level. AEP provided draft language consistent with its recommendation. AEP also noted that §25.53, relating to Electric Service Emergency Operations Plans, already requires a TDU to include TEEEF usage in its emergency operations plan.

OCSC recommended the phrase "sufficient level of detail" under §25.56(g) be revised because it is ambiguous. Specifically, OCSC recommended the provision provide context and specificity on what is meant, otherwise TDUs may provide to ERCOT inconsistent amounts and types of information for evaluating system restoration planning.

Commission Response

The commission deletes the requirement under §25.56(g) for a TDU's EOP to include a sufficient level of detail for system restoration planning by ERCOT because it is unnecessary. ERCOT neither refers to TDU EOPs for system restoration purposes nor intends to use TEEEF for system restoration in a black start event. If a TDU proposes TEEEF be used for black start, then the TDU would do so through their black start plan rather than through their EOPs. Accordingly, the commission declines to implement the changes requested by commenters because they are moot.

Proposed §25.56(h) - Eligible costs

Proposed §25.56(h) establishes that the reasonable and necessary costs of leasing, maintaining, and operating a TEEEF, plus the return associated with those costs, are eligible for cost recovery. Additionally, proposed §25.56(h) specifies that a return on eligible costs under the section must be applied starting on the date that a TEEEF is available for service.

CenterPoint recommended that proposed subsection (h) be revised to expressly permit the recovery of costs associated with TEEEF usage under mutual assistance programs. OPUC disagreed with CenterPoint that TEEEF procured under a mutual assistance program should be recoverable. OPUC commented that TDUs already receive compensation from its own TEEEF leases under the proposed rule, and that when a TDU requests TEEEF through a mutual assistance program, it is because the TDUs' own planning and leases were insufficient. OPUC endorsed mutual assistance programs generally but noted that such programs are only supplemental during an emergency. OPUC pointed out that emergency leasing without preapproval is already contemplated by the proposed rule, and that a TDU may seek recovery of those costs, making recovery through mutual assistance programs unnecessary.

Commission Response

The commission agrees with CenterPoint that a TDU should allowed to seek recovery of costs associated with mutual assistance agreements or programs. Accordingly, the commission adds new §25.56(f)(2) to authorize TDUs to loan its leased TEEEF, or otherwise utilize its leased TEEEF in another TDU's service territory, under a mutual assistance agreement or program, provided that all costs and reimbursements are properly accounted for and reconciled. Additionally, the commission revises proposed §25.56(j)(4) by adding new §25.56(j)(4)(A) and (B) to require that any revenues associated with mutual assistance agreements or programs are properly reconciled against TEEEF costs.

AEP commented that proposed §25.56(h) and its sub-provisions are inconsistent with PURA §39.918(h)(1) because it does not conform with the requirement that "allows a utility to recover a return on the present value of future payments required under (TEEEF) leases and the timing of the application of the carrying charges at a utility's weighted average cost of capital (WACC)." AEP provided draft language consistent with its recommendation.

Commission Response

The commission disagrees with AEP that proposed §25.56(h) is inconsistent with PURA §39.918. However, to address AEP's concern, the commission aligns proposed §25.56(h)(1) and (2) by including the phrase "including the present value of future payments required under the lease" in §25.56(h)(2).

The commission also modifies §25.56(h)(2) to remove "(t)he return must be applied beginning on the date that the TEEEF is available for service." This modification aligns the adopted rule with commission precedent in prior TEEEF-related proceedings in which rates were approved with the return beginning on the date costs were incurred.

Proposed §25.56(j) - Cost recovery

Proposed §25.56(j) establishes that a TDU may request recovery of eligible costs under the section through a standalone TEEEF rider proceeding, DCRF proceeding, or another appropriate ratemaking proceeding. Additionally, proposed §25.56(j) establishes requirements for cost allocation methodology, notice of cost recovery proceedings and new rates, affiliate contracts, and temporary rates and reconciliation.

TNMP recommended proposed §25.56(h)(1) be revised to make it clear that a determination on the reasonableness and necessity of costs should not be made during a DCRF or standalone TEEEF proceeding, but instead should only occur during a base-rate proceeding.

TNMP recommended that proposed §25.56(j)(1) should be revised to limit commission review of TEEEF costs to only occur in a base-rate proceeding. TNMP noted that the proposed language contemplates cost recovery in a base-rate proceeding as well as a DCRF or standalone TEEEF proceeding and that Question 1 of the issued questions for comment is accordingly inconsistent with the rule language. TNMP commented that a review of reasonableness and necessity of costs can only occur in a base-rate proceeding.

AEP commented that it is unclear what level of review and inclusion of TEEEF costs is required under proposed §25.56(j)(1)(F). AEP noted that proposed §25.56(j)(1) indicates a DCRF as an eligible proceeding to recovery eligible TEEEF costs, however a DCRF is limited by statute to a maximum of 75 days and therefore would provide insufficient time to perform a prudence review of TEEEF costs. In contrast, AEP commented that a standalone proceeding, such as a base-rate case, would provide sufficient time. AEP also commented that proposed §25.56(j)(4) appears to be conditional such that a TDU could request recovery through a DCRF or standalone TEEEF proceeding with the option of deferring a full prudence review to a base-rate proceeding. AEP noted that making prudence reviews permissive in the initial cost recovery proceeding for TEEEF provides a TDU more flexibility given the varying sizes of TEEEF and each TDU's financial status. AEP provided draft language consistent with its recommendations.

Commission Response

The commission agrees with commenters that the review of, and determination on, reasonableness, necessity, and prudence of TEEEF costs should be made in base-rate proceedings. Accordingly, the commission adds new §25.56(j)(1)(G) that states the reasonableness, necessity, and prudence of TEEEF costs will only be reviewed and determined in a base-rate proceeding unless good cause exists to review them sooner, mirroring the standard for DCRF proceedings.

TEC recommended that proposed §25.56(j)(1)(B) be revised to include a TEEEF cost exemption for wholesale transmission customers that provide their own distribution services. TEC recommended that if a wholesale customer, such as an electric cooperative, operates its own distribution services, no cost recovery of TEEEF should be borne by retail or wholesale transmission customers. TEC explained that some electric cooperatives might be served as wholesale transmission service customers from a TDU, but the cooperative itself provides distribution services, therefore neither the electric cooperative nor its members would benefit from a TDU's TEEEF operations intended to serve the TDU's distribution customers.

Similarly, LCRA recommended proposed §25.56(j)(1) be revised to be compatible with rate recovery by river authorities, which do not have a distribution tariff or DCRF, and instead recovers non-transmission costs under commission-approved wholesale transformation and metering tariffs. LCRA provided draft language consistent with its recommendation.

Commission Response

The commission agrees with TEC that it would be inappropriate for TEEEF costs to be recovered from wholesale transmission service at transmission voltage customers; however, PURA 39.918 does not exclude the provision of TEEEF service to wholesale distribution service customers receiving wholesale transmission service at distribution voltage, and therefore excluding such customers from TEEEF cost recovery would be inappropriate. Accordingly, the commission revises §25.56(j)(1)(B) to require TEEEF costs to not be allocated to or collected from transmission service customers or wholesale transmission service at transmission voltage customers. This modification also addresses LCRA's concern.

OPUC recommended the presumption of reasonableness for cost allocation under §25.56(j)(1)(C) be removed. OPUC also recommended that the allocation of TEEEF costs between customer classes should generally follow the rate class allocation factors established in the TDU's most recent base-rate proceeding but be eligible for adjustment depending on TEEEF usage and the customer classes benefiting from such usage. OPUC noted that such cost allocation issues could be determined in the applicable rate proceeding where the TEEEF costs are sought to be recovered, rather than under the proposed rule, so that parties to such cases may engage in the full discovery process to determine the appropriate method of recovery for a given TDU. OPUC also recommended that, if the commission agrees that a prudence review of TEEEF costs should be performed at the time the application is reviewed, then proposed §25.56(j)(4) be revised accordingly but should otherwise maintain the language requiring refunds for any over-recovery of costs.

Commission Response

The commission disagrees with OPUC and declines to modify the proposed rule's cost allocation methodology as requested. Removing the presumption of reasonableness from §25.56(j)(1)(C) would introduce further litigation for little benefit as the rate class allocation factors have already been established in the TDU's most recent base-rate proceeding. It would also be impractical to adjust those factors based on actual use. However, the commission makes clarifying changes to §25.56(j)(1)(C) to indicate that an allocation of TEEEF costs among distribution-level rate classes, based on substation-level class non-coincident peak demand, regardless of the time at which the class demand occurs, from a TDU's current or most recent base-rate proceeding, is presumed to be reasonable.

Additionally, the commission declines to modify §25.56(j)(4) in the manner OPUC recommends because it is moot. Prudence reviews of TEEEF costs will only occur at TDUs' base-rate proceedings, not at TDUs' preapproval proceedings.

Oncor expressed concern about proposed §25.56(j)(1)(D) which prohibits TEEEF rates from being established on a per-kilowatt-hour basis for any customer class that includes demand charges. Oncor stated that the rationale for the inclusion of this provision is unclear, given that "energy provided to a customer from TEEEF is still energy, just like energy provided to the customer from the grid during normal conditions." Oncor commented that it is not opposed to the use of a demand allocation, but it is unclear why the possibility of an energy charge is excluded since the demand allocation and the energy charge do not need to be the same.

Commission Response

The commission disagrees with Oncor and maintains that exclusion of an energy charge is appropriate in §25.56(j)(1)(D). The primary purpose of TEEEF is to provide resiliency and reliability during a crisis. Ratepayers are paying for TEEEF capacity to be available; therefore, a demand charge is more appropriate. Moreover, demand charge cost recovery is more stable and predictable.

Oncor recommended proposed §25.56(j)(1)(E) be deleted from the rule or revised to state that, if a TDU amends an existing lease and that amendment results in lower payments by the TDU, then the TDU must submit an application to reflect the reduced rate of cost recovery necessary within six months or address it in the TDU's next DCRF filing, whichever is sooner. Oncor commented that the language of the provision as proposed is unclear because it is unlikely that a TDU will ever over-recover for TEEEF costs because of the regulatory lag inherent to a TDU's business. Oncor explained that PURA §39.918(i) and subsection (i) of the proposed rule require that TEEEF leasing and operation costs be deferred to a regulatory asset, meaning that any over-recovery would "only last until the monthly lease payments and other expenses in the regulatory asset accumulate" until such costs again exceed the over-recovery. Oncor further noted that in the TDU's next standalone TEEEF, DCRF, or other ratemaking proceeding, recovery would reset to reflect the level of the regulatory asset such that any over-recovery would be refunded.

Commission Response

The commission declines to delete §25.56(j)(1)(E) as requested but agrees with and implements Oncor's alternative recommendation to specify a timeframe. Specifically, the commission revises §25.56(j)(1)(E) to require a TDU to submit an application to reflect the reduced rate of cost recovery necessary within three months or address it in the TDU's next DCRF filing, whichever is sooner, if a TDU amends an existing lease that results in lower payments by the TDU.

REP Coalition recommended that REPs be provided a 45-day notice period if TEEEF costs are recovered in a standalone TEEEF rider proceeding or in another ratemaking proceeding. REP Coalition noted that because proposed §25.56(j)(1) authorizes a TDU to request recovery of TEEEF costs in a DCRF proceeding, a 45-day notice to REPs is therefore required under §25.243(e)(6)(E), relating to Distribution Cost Recovery Factor (DCRF), and PURA §36.210(b)(2). REP Coalition also recommended that for costs recovered in a TEEEF rider, any new rates or rate changes be effective either on March 1 or September 1 to align with other TDU rate changes. REP Coalition explained that this change would help reduce the number of times customers see TDU rates change annually. REP Coalition provided draft language consistent with its recommendations.

Commission Response

The commission agrees with REP Coalition and makes clarifying changes to §25.56(j)(1)(A) regarding the provision of notice to REPs of approved rates no later than the 45th day prior to the effective date of the approved rate. However, the commission declines to implement REP Coalition's recommended changes to §25.56(j)(1)(B) regarding the March 1 or September 1 effective dates.

REP Coalition recommended revising proposed §25.56(j)(1) to require a TDU include the after-action report for a TEEEF deployment in the cost recovery application for the same TEEEF deployment. REP Coalition also recommended requiring the TDU to file all after-action reports with its next base-rate proceeding where the commission will review and reconcile TEEEF costs initially approved in a DCRF proceeding. REP Coalition provided draft language consistent with its recommendations.

Commission Response

The commission agrees with REP Coalition's recommendation and implements the recommended change as part of §25.56(j) with clarifying revisions. Specifically, the commission adds new §25.56(j)(1)(H) to require a TDU's application in any proceeding in which TEEEF costs are reviewed for reasonableness, necessity, or prudence to include the after-action reports for each significant power outage that qualified for TEEEF energization and occurred during the period for which recovery is requested. The new provision also requires an application to include the TEEEF leases, as confidential filings, for any leased TEEEF for which costs are being reviewed.

REP Coalition recommended deleting proposed §25.56(j)(1)(B) so as to not unnecessarily restrict the commission. REP Coalition acknowledged that the definition of "significant power outage" is intended to apply to losses of electric power for distribution customers, PURA §39.918(a)(1)(D) also applies to losses of electric power that create a risk to public health or safety because the outage impacts a critical infrastructure facility. REP Coalition accordingly recommended providing more flexibility under the rule to determine whether it is appropriate to, on a case-by-case basis, collect TEEEF costs from transmission customers "in the event TEEEF is used to aid in the restoration of power to a critical infrastructure facility that takes service at transmission voltage."

Commission Response

The commission disagrees with REP Coalition and declines to delete proposed §25.56(j)(1)(B). Transmission customers already bear significant distribution costs, and, per the plain language of PURA §39.918(a)(1) and (b)(1), the primary intended use for TEEEF is to provide temporary emergency electric energy to a TDU's distribution customers.

TNMP recommended proposed §25.56(j)(1)(F) be revised to clarify that a TDU is not required to obtain a second determination of reasonableness and necessity if a set of TEEEF costs have already been determined to be reasonable and necessary in a previous rate case proceeding. TNMP commented that the provision is unclear as to whether a TDU must include, for a given TEEEF cost recovery proceeding, TEEEF costs that have already been considered and approved in a previous docket.

Commission Response

The commission agrees with TNMP but declines to implement the recommended changes because they do not capture the intent of this provision, which is to prevent the proliferation of disjointed TEEEF riders and proceedings. The commission revises the proposed rule to clarify that TEEEF costs must not be included in base-rates, that all TEEEF costs must be recovered through a single rider, and that a TDU with a previously established TEEEF rider may recover additional TEEEF costs by updating its existing TEEEF rider.

OCSC commented that the rule does not specify clear procedures for the standalone TEEEF rider proceeding such as "notice, intervention, deadlines for review and processing, and effective date." OCSC recommended that TEEEF riders specifically authorize intervention and provide for sufficient time for affected parties to "evaluate the prudence, reasonableness, and necessity of the requested costs."

Commission Response

The commission declines to modify the proposed rule as requested by OCSC because standalone TEEEF rider proceedings will not include a prudence review, as suggested by OCSC. These are much more straightforward proceedings, and the presiding officer will set an appropriate procedural schedule.

Oncor recommended revising proposed §25.56(j)(4) to state that a refund of over-recovery is only necessary if and when the over-recovery exceeds the current level of the regulatory asset or the projected level of the regulatory asset at the end of the refund proceeding.

Commission Response

The commission agrees with Oncor that it would be appropriate to offset any over-recovered amounts associated with TEEEF--including any over-recovered return and also including carrying charges calculated at WACC--against the balance of a regulated asset if the balance of the regulatory asset exceeds the total refund due to customers. The commission disagrees with Oncor that the balance considered should be the projected balance of the regulatory asset; instead, the actual amount of regulatory asset should be considered in a compliance proceeding. The commission revises §25.56(j)(4) to account for the specific reconciliation procedures associated with TEEEF costs. Whether a refund should be applied as a credit or reduction to any deferred assets is an issue to be determined in the proceeding in which the refund is being reviewed.

Oncor further recommended that, if the language regarding the return of any over-recovery to customers is retained, the provision be revised to change the interest rate for over- or under-billings. Specifically, Oncor recommended the provision utilize the commission-prescribed rate as published in Project 45319 for the applicable period, instead of requiring the interest to be charged as the TDU's weighted average cost of capital most recently approved for the TDU. Oncor explained that this approach is consistent with the application of interest amounts for over-billing from interim transmission cost of service or DCRF updates under Project 45319. Oncor noted that §25.56(j)(4) also does not address or account for the possibility of a TDU under-recovering TEEEF costs.

Commission Response

The commission disagrees with Oncor and declines to implement the recommended change. Oncor's contention regarding the interest rate applied to interim transmission cost of service (TCOS) and DCRF refunds is incorrect as those proceedings require a refund with carrying charges calculated using the TDU's WACC, not the over- or under-billing interest rate. Carrying charges on improperly over-recovered amounts should mirror the carrying charges on costs associated with TEEEF and be based on the TDU's WACC in order to make ratepayers whole and to avoid providing an economic profit to the TDU for improperly collected amounts. The commission revises §25.56(j)(4) to include language that makes the carrying charges calculated on improper over-recoveries of TEEEF and long lead-time facility costs consistent with the calculation of carrying charges for refunds resulting from DCRF and interim TCOS reconciliations.

Proposed §25.56(k) - Grandfathering of previously leased TEEEF

Proposed §25.56(k) establishes that, unless a lease is amended, renewed, or extended, any lease for a TEEEF that a TDU entered into before the effective date of the section is exempt from the contested case proceeding under proposed §25.56(c). Additionally, proposed §25.56(k) establishes that any costs related to a TEEEF that were deemed reasonable and necessary in a DCRF before the effective date of the section are not required to be reviewed for reasonableness and necessity in a TDU's next base-rate proceeding.

OPUC recommended the inclusion of language in proposed §25.56(k) that would require comprehensive review of existing TEEEF lease amendments, extensions, or renewals. Similarly, REP Coalition recommended that proposed §25.56(k)(2) be revised to require TEEEF leases entered into prior to the effective date of the rule to undergo the commission preapproval process under proposed §25.56(c).

Commission Response

The commission declines to implement the recommended changes because it is impracticable. TDUs that have procured TEEEF prior to the rule have done so in accordance with PURA §39.918 after extensive commission proceedings. Requiring TDUs to re-apply for and re-litigate TEEEF leases that have already been approved by the commission would lead to an inefficient use of commission and stakeholder resources and undermine prior commission orders.

Oncor requested proposed §25.56(k)(3) be revised such that any costs previously deemed reasonable and necessary by the commission in any proceeding, such as a DCRF, base-rate proceeding, or otherwise, are not subject to further review on that basis. Specifically, "any costs, capacity, lease terms, or vendor/supplier bidding or solicitation processes" that the commission has already reviewed in a prior proceeding should not be subject to further prudence review. In contrast, Oncor highlighted that any costs incurred by a TDU that are not addressed in a prior proceeding are appropriate for further review and litigation.

Commission Response

The commission agrees with Oncor that proposed §25.56(k)(3) does not fully capture the costs associated with TEEEF leases that have previously been deemed prudent, reasonable, and necessary. The commission further notes that each of the provisions of proposed §25.56(k) are already substantively addressed by other sections of the rule. Specifically, TEEEF leases entered into before the effective date of §25.56 are already exempt from the preapproval process under §25.56(c), because the process did not exist at the time of execution. Similarly, the provisions of §25.56(c) require a TDU to obtain commission approval prior to renewing or extending its existing TEEEF leases. Lastly, TEEEF-related expenses that have already been deemed prudent are not subject to further prudence review, because that review has already occurred and been approved by commission order. Accordingly, the commission modifies the rule to remove proposed §25.56(k) because it is surplusage and could result in ambiguity, such as in the instance noted by Oncor.

Proposed §25.59. Long Lead-Time Facilities.

Proposed §25.59(a) - Applicability

Proposed §25.59(a) provides that a TDU may procure, own, operate, and recover costs of long lead-time facilities. Proposed §25.59(a) further provides that §25.59 applies to a TDU, other than a river authority, that operates distribution facilities in the ERCOT region to serve distribution customers.

OPUC recommended the exemption of river authorities in subsection (a) from the rule's applicability be removed. OPUC commented that PURA §39.918 does not prohibit a river authority from leasing or operating long-lead time facilities and concluded that such a limitation could impact a river authority's capability to provide emergency energy to its customers during significant power outages. OPUC noted that river authorities would still otherwise be required to meet all of the rule's other applicability requirements.

Commission Response

The commission agrees with OPUC and modifies the rule such that it also applies to river authorities.

Proposed §25.59(b) - Definitions

Proposed §25.56(b) establishes the definitions for "Long-lead time facilities" and "Significant power outage."

OPUC recommended proposed clause §25.59(b)(2)(C)(i) be revised for clarity. Specifically, OPUC recommended the phrase "affects a significant number of (customers)" be revised to be more informative. OPUC explained that the phrase does not provide sufficient guidance to TDUs to determine when an outage is significant and that the provision could be revised to be more objective.

Commission Response

The commission declines to implement the proposed changes to the definition of "significant power outage" as OPUC recommend because it is unnecessary for the same reasons as previously stated in response to OPUC's identical recommendation for the TEEEF rule, §25.56(b). Generally restated, the definition of "significant power outage" as defined under §25.59(b)(2) adheres to the language provided by PURA §39.918(a)(1) and (2). Moreover, in the case of long lead time facilities, unlike with TEEEF, there is no risk of use of a TDU's use of a long lead time facility interfering with the competitive market, making definitional precision less important.

Oncor expressed concern with limiting the definition of "long lead-time facilities" under §25.59(b)(1) to facilities that require at least six months to obtain. Oncor averred that the primary need for the rule is because of the lengthy and variable timeframe for a TDU to procure such facilities. While six months is realistic, it is possible that procurement be shorter or longer depending on certain factors. Oncor emphasized that a TDU should not be penalized for such outcomes beyond its control. Oncor provided draft language consistent with its recommendation.

Commission Response

The commission acknowledges Oncor's concern and revises the definition of "long-lead time facilities" under §25.59(b)(1) to state that such facilities consist of those "that the TDU reasonably anticipates will require at least six months to obtain." The commission also adds language to §25.59(g)(1) to require a TDU to provide sufficient documentation to support a determination that the facilities procured meet the criteria for long lead-time facilities.

Proposed §25.59(c) - Contracts for Long Lead-Time Facilities

Proposed §25.59(c) authorizes a TDU to enter into contracts to procure long lead-time facilities including cooperative agreements with another TDU or procurement subscriptions with a transmission and distribution equipment supply service company or other third party as described by proposed §25.59(c).

OPUC recommended the commission consider a pre-approval process for long lead time facility contracts and cooperative agreements and after-action reporting that are akin to the processes for TEEEF facilities under proposed §25.56. OPUC explained that such procedures are necessary because the risks inherent to long-lead time facility procurement are the same as for TEEEF procurement. Specifically, such risks include the possibility that long-lead time facility costs may be "excessive or disproportional" to the benefit received. OPUC noted that PURA §39.918 does not differentiate between procurement of either type of facilities and therefore there is no reason to treat them differently in the rule.

Commission Response

The commission declines to modify the rule to require pre-approval and after-action reporting for long lead time facilities as recommended by OPUC. Unlike TEEEF, long lead-time facilities may be used in a TDU's regular course of business - not just during significant power outages - making the risk of such a facility going completely unused much less likely. The purpose of §25.59 is to ensure that the risk of expenses associated with long-lead time facilities being disallowed does not prevent TDUs from having them available to address a significant power outage, should one occur. However, these procurements will still be subject to review, and any costs that are unreasonable, unnecessary, or imprudent will be disallowed at the TDU's next comprehensive base-rate proceeding.

Oncor recommended renaming proposed subsection (c) as "Procurement of long-lead time facilities" to indicate the subject matter of the provision more clearly. Oncor also recommended revising the first sentence of proposed §25.59(c) to use the same "procure, own, and operate" phrasing used by PURA §39.918(b)(2). Oncor provided draft language consistent with its recommendation.

Commission Response

The commission agrees with Oncor and renames subsection (c) "Procurement of long-lead time facilities.

Proposed §25.59(e) - Eligible costs

Proposed §25.59(e) provides that the reasonable and necessary costs of procuring, owning, maintaining, and operating long lead-time facilities are eligible for recovery under §25.59 beginning on the date that a long lead-time facility is procured. Proposed §25.59(e) further provides that those reasonable and necessary costs include a return on investment that may be applied beginning on the date that a long lead-time facility is placed into service.

Similar to its recommendation for §25.56, OPUC recommended the commission consider reviewing the prudence of costs when the commission approves a contract or cooperative agreement for long-lead time facilities.

Commission Response

The commission declines to modify the rule to require the commission to review the prudence of costs when the commission approves a contract or cooperative agreement for long-lead time facilities, because the commission did not adopt OPUC's recommendation to pre-approve such contracts or cooperative agreements making such a recommendation moot. Moreover, reviewing prudence of costs during base-rate proceedings is consistent with established ratemaking and regulatory practices for regulated utilities, whereby the commission defers to a TDU's utility management expertise in making management decisions, but retains the flexibility to disallow any imprudently-incurred expenses during the base-rate proceeding. If the commission deems the expenses prudent up front, it would lose the ability to disallow imprudently-incurred expenses during subsequent rate cases.

Oncor recommended §25.59(e)(1) be revised to conform to the timing in proposed (e)(2) and therefore authorize cost recovery beginning on the date a long lead-time facility is placed into service. Oncor expressed concern with the differing timing in §25.59(e)(1) between when a TDU may recover costs associated with long-lead time facilities beginning with procurement compared with the timing in §25.59(e)(2) that provides that a TDU may apply and earn a return on such costs on the date such a facility is placed into service. Oncor noted that this timing difference is inconsistent with statute. Specifically, PURA §39.918(h)(2) authorizes the commission to permit a TDU to recover the reasonable and necessary costs of procuring, owning, and operating such facilities using the TDU's most recent rate of return. Oncor emphasized that the statutory language does not indicate that "the timing of earning a return on the investment in long-lead time facilities should differ from the timing of recovering the costs."

Oncor also noted that the date a long-lead time facility is procured is ambiguous given that there is a gap of several months between the date the TDU purchases and later receives the facilities. Specifically, it is ambiguous whether the date of procurement refers to the initial purchase date or the date of receipt of the facilities. Oncor also stated that it interprets the term "placed into service" to conform with its historical interpretation for utility plant equipment and land purchases which are based on the date of received and is available for service, regardless of whether it has yet been placed into service. Oncor noted that this interpretation is consistent with the Federal Energy Regulatory Commission's Uniform System of Accounts. Oncor requested that if the commission's interpretation of the phrase differs, then further clarification be provided in proposed subsection (e). Oncor provided draft language consistent with its recommendation.

Commission Response

The commission disagrees with Oncor that "placed into service" is a more appropriate term than "procured" in the context of §25.59(e) because the terms hold different meanings. For example, a long lead-time facility, such as a transformer, is "placed into service" when it is actually installed and operational, not when it is received from a vendor or placed in a warehouse for storage. PURA §39.918 provides for TDUs to recover the reasonable and necessary costs, and associated returns, of procuring, owning, and operating long lead-time facilities. Replacing "procured" with "placed into service" in §25.59(e)(2) as requested by Oncor would effectively disallow a TDU to book, and subsequently recover, costs incurred prior to placing long lead-time facilities into service (i.e., costs of procurement), which is in conflict with PURA §39.918. Accordingly, the commission declines to modify the rule as requested.

The commission agrees with Oncor that, because PURA §39.918 provides for TDUs to recover the reasonable and necessary costs of long lead-time facilities, including a rate of return, the booking of costs and application of rate of return should happen parallel to each other. Accordingly, the commission modifies §25.59(e)(2) to apply the rate of return beginning on the date that a facility is procured, instead of placed into service.

Additionally, the commission modifies §25.59(e)(1) to provide for reasonable and necessary costs of procuring, owning, and operating long lead-time facilities to be recovered to the extent that they are not otherwise included in the TDU's rates.

CenterPoint and AEP recommended §25.59(e)(2) be revised to authorize a TDU to collect a return on its investment in a manner consistent with PURA §39.918 by deleting the last sentence of the provision. Specifically, PURA §39.918(i) states "the commission shall authorize a transmission and distribution utility to defer for recovery in a future ratemaking proceeding the incremental operations and maintenance expenses and the return, not otherwise recovered in a rate proceeding, associated with the leasing or procurement, ownership, and operation of the facilities."

CenterPoint recommended removing the phrase "placed into service" because the requirement is inconsistent with the ratemaking treatment for long-lead time facilities. CenterPoint explained that under the Federal Energy Regulatory Commission Uniform System of Accounts 1540, long-lead time facilities are classified as materials and supplies which are a component of rate base under §25.231(c)(2)(B)(i), relating to Cost of Service, and therefore included in the overall calculation for a TDU's rate of return. CenterPoint noted that the proposed phrasing implies that long-lead time facilities that become capitalized would be eligible for a rate of return only after the entire project is placed. CenterPoint commented that this position contradicts other commission rules that provide that all such costs are eligible for a return. CenterPoint also stated that the proposed language may be impractical and unduly burdensome because it would require tracking of long-lead time facilities "recorded to construction in order to determine the appropriate time to discontinue recording return on those amounts once they begin to be recovered in rates as part of invested capital."

AEP commented that the intention of PURA §39.918 was to authorize a TDU to earn a return on its investment into long-lead time facilities and that the provision should therefore conform to the statutory language.

Commission Response

Consistent with the response above, the commission modifies §25.59(e)(2) to specify that the return associated with long lead-time facility costs may be applied beginning on the date that such a facility is procured, instead of placed into service.

Proposed §25.59(f) - Deferred recovery of certain eligible costs

Proposed §25.59(f) authorizes a TDU to defer the recovery of incremental operations and maintenance expense as well as the return, not otherwise recovered in a rate proceeding, associated with the procurement, ownership, maintenance, and operation of long lead-time facilities to a future ratemaking proceeding.

Oncor recommended revising proposed §25.59(f) because the provision does not include the term "regulatory asset" which is included in the TEEEF rule under §25.56(i). For consistency between both rules, Oncor recommended the term be included in §25.59(f). Oncor provided draft language consistent with its recommendation.

Commission Response

The commission agrees with Oncor and modifies the rule to clarify that a TDU may defer the recovery of certain incremental operations and maintenance expenses using a regulatory asset.

Proposed §25.59(g) - Cost recovery

Proposed §25.59(g) prescribes the proceedings under which a TDU may request recovery of eligible costs of long lead-time facilities and further includes requirements regarding notice, affiliate contracts, and temporary rates and reconciliation.

Similar to its recommendations for §25.56, OPUC requested that TDUs provide notice to OPUC of "any filing under this section" within 10 days.

Commission Response

The commission interprets OPUC's comment to be requesting 10 days notice of any application for pre-approval to procure long lead-time facilities, consistent with its comment to §25.56. The commission declines to implement this recommended change because the commission declined to implement OPUC's corresponding suggestion that long lead-time facilities undergo a pre-approval process. Any notice requirements would therefore be handled under the respective commission rule that governs the rate proceeding in which recovery of costs for long lead-time facilities is requested.

OPUC recommended that prudence review of long-lead time facility costs occur during the "application's review process" and that provisions be added to the rule to refund to consumers any over-recovery of long-lead time facility costs.

Commission Response

The commission declines to require a prudence review of long-lead time facility costs during the "application's review process" as requested by OPUC. The commission interprets this comment to be recommending that prudence review occur during a pre-approval process for long-lead time facility costs. The commission previously declined to include such a pre-approval process.

The commission also declines to modify the rule to require refunds of any over-recovery, because the proposed rule already requires rate reconciliation and, if appropriate, refunds.

Oncor recommended §25.59(g)(4) be revised to state that a refund of over-recovery is only necessary if and when the over-recovery exceeds the current level of the regulatory asset or the projected level of the regulatory asset at the end of the refund proceeding because over-recovery for long-lead time facilities is unlikely.

Commission Response

The commission agrees with Oncor that it would be appropriate to offset any over-recovered amounts associated with long lead-time facilities--including any over-recovered return and also including carrying charges calculated at WACC--against the balance of a regulated asset if the balance of the regulatory asset exceeds the total refund due to customers. The commission disagrees with Oncor that the balance considered should be the projected balance of the regulatory asset; instead the actual amount of regulatory asset should be considered in a compliance proceeding. The commission revises §25.59(g)(4) to account for the specific reconciliation procedures for costs associated with long lead-time facilities. Whether a refund should be applied as a credit or reduction to any deferred assets is an issue to be determined in the proceeding in which the refund is being reviewed.

Oncor also recommended that the requirement for the interest to be charged be based on the TDU's most recently approved WACC should be replaced with the commission-prescribed interest rate for over-billing or under-billing as prescribed under Project 45319, which is used for DCRF and interim TCOS updates.

Commission Response

The commission disagrees with Oncor and declines to implement the recommended change for the same reasons stated in response to this recommendation for §25.56. Namely, the commission disagrees with Oncor's contention regarding consistency with interim TCOS and DCRF refunds as those proceedings require a refund with carrying charges calculated using WACC, not the over- or under-billing interest rate. Carrying charges on over-recovered amounts should mirror the carrying charges on costs associated with long lead-time facilities. The commission revises §25.59(g)(4) to make the carrying charges calculated on over-recovery of TEEEF and long lead-time facilities consistent with the calculation of carrying charges resulting from DCRF and interim TCOS proceedings.

Oncor recommended a grandfathering provision be included in §25.59(g) that is similar to the TEEEF rule under §25.56(k). Oncor noted that PURA §39.918 covers long lead time facilities as well as TEEEF, therefore a TDU that has had prior leases approved by the commission for long-lead time facilities should be exempt from certain provisions, such as the notice requirements under §25.59(g)(2). Oncor provided draft language consistent with its recommendation.

Commission Response

The commission declines to implement the recommended change. In a rate proceeding, notice is required for all costs that have not been reconciled. To address Oncor's concerns, the commission adds clarifying language to §25.59(g)(2) to indicate that notice is required for all costs that have not been reconciled as of the effective date of §25.59.

Statutory authority

The new sections are adopted under the following provisions of PURA: §14.001, which provides the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; §14.002, which provides the commission with the authority to make adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; and §39.918, which directs the commission to allow TDUs to lease and operate TEEEF to aid in restoring power to a TDU's distribution customers during a significant power outage, and to allow TDUs to procure, own, and operate, or enter into a cooperative agreement with other TDUs to procure, own, and operate jointly, long lead-time transmission and distribution facilities that will aid in restoring power to a TDU's distribution customers following a significant power outage.

Cross reference to statutes: Public Utility Regulatory Act §§14.001, 14.002, and 39.918.

§25.56. Temporary Emergency Electric Energy Facilities (TEEEF).

(a) Applicability. This section establishes the requirements for a transmission and distribution utility (TDU) to lease, operate, and recover costs associated with a temporary emergency electric energy facility (TEEEF). This section applies to a TDU that operates facilities in the Electric Reliability Council of Texas (ERCOT) region to serve distribution customers.

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

(1) Affected generator or load resource--a generator or load resource that:

(A) is registered with ERCOT for purposes of settlement; and

(B) is located within the portion of the grid that is isolated from the bulk power system and where a TEEEF is energized to restore power.

(2) Significant power outage--an event that:

(A) causes ERCOT to order a TDU to shed load;

(B) the Texas Division of Emergency Management, ERCOT, or the executive director of the commission determines is a significant power outage; or

(C) results in a loss of electric power that:

(i) affects a significant number of a TDU's distribution customers, and has lasted, or is expected to last, for at least six hours;

(ii) affects distribution customers of a TDU in an area for which the governor has issued a disaster or emergency declaration;

(iii) affects distribution customers served by a radial transmission or distribution facility, creates a risk to public health or safety, and has lasted, or is expected to last for, at least 12 hours; or

(iv) creates a risk to public health or safety because it affects a critical infrastructure facility that serves the public such as a hospital, health care facility, law enforcement facility, fire station, or water or wastewater facility.

(3) Temporary Emergency Electric Energy Facility (TEEEF)--a facility that provides electric energy to distribution customers on a temporary basis.

(c) Authorization to lease TEEEF. Except as authorized under subsection (d) of this section, a TDU must not enter into, renew, or extend any lease involving a TEEEF without receiving prior commission authorization. Authorization under this subsection applies to a TDU's TEEEF fleet. A TDU may enter into one or more leases for TEEEF, simultaneously or consecutively, provided that the capacity and characteristics of its leased TEEEF fleet complies with the authorization provided under this subsection at all times.

(1) Contents of application. An application under this subsection must include the following:

(A) The TDU's history with TEEEF, including:

(i) Whether the TDU is currently or has previously been authorized by the commission to lease TEEEF, the details of existing or prior authorizations, and each docket number in which the authorization was granted;

(ii) A description of all TEEEF the TDU has under lease at the time of the application, including the total capacity the TDU has under lease, the length of the lease or leases, a description of the capacity, intended functions, and relevant characteristics of each leased unit, and whether each leased unit has been energized to aid in restoring power during a significant power outage;

(iii) A description of any previous emergency leases of TEEEF or prior use of another TDU's TEEEF under a mutual assistance agreement or program. A TDU must include an explanation for the necessity of each use of TEEEF under an emergency lease or mutual assistance agreement or program;

(iv) A copy of every after-action report submitted by the TDU to the commission under this section during the five years prior to the date on which the application was filed, including a cover page with summary statistics on significant power outages and TEEEF energizations in the TDU's service territory; and

(v) The interchange item number of the TDU's most recently filed emergency operations plan filed in project no. 53385.

(B) The total capacity of TEEEF the TDU is requesting authorization to lease, each function the requested TEEEF will serve (e.g. to restore power to individual facilities, to restore power to feeders to assist in load rotation, etc.) and how much of the requested capacity is requested for each function, and the length of time for which the TDU is requesting authorization. In support of its request, the TDU must include the following:

(i) A description of any necessary characteristics a TEEEF unit must have to perform each of the functions for which authorization is requested. These characteristics should be identified with enough specificity to allow the commission to evaluate, in a subsequent proceeding, whether the TDU's leased TEEEF fleet complies with the commission's authorization. These characteristics should include, as applicable, the capacity or range of capacities of individual units, the mobility of individual units, the types of connections the units must be compatible with, such as mid-span or point-of-use, fuel type, and whether the units can fulfill the function individually or with multiple units working in tandem;

(ii) An explanation with any necessary supporting documentation that the functions the TEEEF is being requested to perform are reasonable and necessary to aid in the restoration of power under this section. This supporting documentation must include, at minimum, historical data on significant power outages that occurred in the TDU's service territory and would have qualified for TEEEF deployment for the five-year period preceding the date of the application, including:

(I) the start and end date of the outage and information on how long customers were affected by the outage;

(II) a description of the events that caused the outage;

(III) the number of affected distribution customers and amount of load, in megawatts, that were affected by the outage; and

(IV) the number and type of critical load, critical care customers, or other critical infrastructure facilities as defined in §25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers) affected by the outage.

(iii) A description of any additional measures being implemented or scheduled for implementation that may mitigate the need for TEEEF, such as the TDU's implementation of a resiliency plan measure under §25.62 of this chapter, relating to Transmission and Distribution System Resiliency Plans.

(C) As appropriate, data provided under this section must be filed in a format native to Microsoft Excel and must permit basic data manipulation functions, such as copying and pasting of data.

(2) The application will be processed in a contested case proceeding as follows.

(A) Sufficiency. An application is sufficient if it includes the information required by paragraph (1) of this subsection and the TDU has filed proof that notice has been provided in accordance with this subsection.

(i) Within 30 calendar days of the TDU filing its application, commission staff must file a recommendation on sufficiency of the application. If commission staff recommends the application be found deficient, commission staff must identify the deficiencies in its recommendation. The TDU will have five working days to file a response, which may include an amendment to the application to attempt to cure the deficiency.

(ii) If the presiding officer determines the application is deficient, the presiding officer will file a notice of deficiency and cite the particular requirements with which the application does not comply. The presiding officer must provide the TDU an opportunity to amend its application. Commission staff must file a recommendation on sufficiency within 10 working days after the filing of an amended application, when the amendment is filed in response to a notice of deficiency.

(iii) If the presiding officer has not filed a written order concluding that the application is deficient within 10 working days after a deadline for a recommendation on sufficiency, the application is deemed sufficient.

(B) Notice and intervention. Within one working day after the TDU files its application, the TDU must provide notice of its filed application, including the docket number assigned to the application and the deadline for intervention in accordance with this paragraph. The intervention deadline is 30 days from the date service of notice is complete. The notice must be provided using a reasonable method of notice to:

(i) all municipalities in the TDU's service area that have retained original jurisdiction;

(ii) all parties in the TDU's last base-rate proceeding;

(iii) each retail electric provider that provides service in the TDU's service area; and

(iv) the Office of Public Utility Counsel.

(3) Commission evaluation and final determination. The commission will authorize a TDU to lease TEEEF under this subsection if it determines that leasing the requested TEEEF is reasonable and necessary to aid in restoring power to the TDU's distribution customers during a significant power outage that qualifies for TEEEF energization. The commission's final order will include the total TEEEF capacity the TDU is authorized to lease, the capacity of TEEEF the TDU is authorized to lease for each function the TEEEF fleet will perform, and the date or dates the authorization expires (i.e., TEEEF leases must not extend past this date). The commission may include additional requirements related to the characteristics the TEEEF the TDU is authorized to lease.

(d) Emergency TEEEF lease.

(1) A TDU may enter into a lease for TEEEF without prior commission approval if the TDU lacks the leased TEEEF generating capacity necessary to aid in restoring power, consistent with subsection (f) of this section.

(2) The amount of TEEEF generating capacity leased by a TDU under this subsection must not exceed the amount of megawatts or length of time necessary to restore electric service to the TDU's distribution customers by more than a reasonable amount.

(3) The TDU must provide sufficient documentation to support the reasonableness, necessity, and prudence of any generating capacity and costs of TEEEF leased by a TDU under this subsection during the TDU's next base-rate proceeding.

(e) Competitive bidding process. Except for an emergency lease under subsection (d) of this section, a TDU must use a competitive bidding process to lease TEEEF under this section.

(1) In any proceeding in which the commission is reviewing the reasonableness, necessity, or prudence of the costs associated with leasing a TEEEF under this section, the commission may also consider whether the contracts the TDU entered into to lease TEEEF were reasonable relative to other bids that were available to the TDU, if any.

(2) In any proceeding in which a TDU is requesting recovery of costs associated with TEEEF that was not leased using a competitive bidding process, the TDU must demonstrate that the TEEEF was leased under an emergency lease consistent with subsection (d)..

(3) A TDU may not enter into a lease for TEEEF with a competitive affiliate of the TDU unless that lease was subject to a competitive bidding process.

(4) If requested by a commissioner or commission staff, a TDU must allow for the inspection of any lease entered into under this section. If the commissioner or commission staff retains a copy of the lease, the lease will be treated as a confidential document if so requested by the TDU.

(f) Energization of TEEEF.

(1) A TDU may energize TEEEF to aid in restoring power to its distribution customers during an event that a TDU reasonably determines is a significant power outage in which:

(A) ERCOT has ordered the TDU to shed load; or

(B) the TDU's distribution facilities are not being fully served by the bulk power system under normal operations.

(2) A TDU may loan its leased TEEEF to other TDUs or otherwise utilize its leased TEEEF in another TDU's service territory under a mutual assistance agreement or program, provided that all costs and reimbursements associated with such a loan or utilization are properly accounted for and reconciled.

(3) A TDU that leases a TEEEF must not sell energy or ancillary services from the facility.

(4) A TEEEF must:

(A) be operated in isolation from the bulk power system; and

(B) not be included in locational marginal price calculations, pricing, or reliability models developed by ERCOT.

(5) Notice. A TDU must issue notices under subparagraphs (A), (B), (C), and (D) of this paragraph to ERCOT and all operators of affected generators or load resources. Notice under this paragraph is not required if the area isolated from the bulk power system does not contain any affected generators or load resources.

(A) Prior to isolation. For an isolation from the bulk power system due to circumstances within a TDU's control in which TEEEF will be energized, a TDU must issue notice at least 10 minutes prior to isolation of an affected area from the bulk power system. For an isolation from the bulk power system due to circumstances beyond a TDU's control in which TEEEF will be energized, a TDU must issue notice as soon as is reasonably practicable. Notices prior to isolation of an affected area from the bulk power system must include:

(i) identification of each substation and modeled load associated with customer load that will be served by TEEEF;

(ii) the total amount of load expected to be served by TEEEF;

(iii) the time the affected area is anticipated to be isolated from the bulk power system;

(iv) the time the affected area is anticipated to be reconnected to the bulk power system;

(v) identification of each generator or load resource that will be an affected generator or load resource following the energization of TEEEF; and

(vi) a statement that any energy produced by an affected generator during the time it is isolated from the bulk power system will not be settled through ERCOT.

(B) Upon isolation. For an isolation from the bulk power grid due to circumstances within a TDU's control in which TEEEF will be energized, a TDU must issue notice immediately upon isolation of an affected area from the bulk power system. For an isolation from the bulk power system due to circumstances beyond a TDU's control in which TEEEF will be energized, a TDU must issue notice as soon as is reasonably practicable. A notice issued under this subparagraph must state the time an affected area's isolation from the bulk power system was completed.

(C) Prior to reconnection. A TDU must issue notice at least 10 minutes prior to the reconnection of an affected area to the bulk power system. A notice issued under this subparagraph must state the anticipated time that an affected area will be reconnected to the bulk power system.

(D) Upon reconnection. A TDU must issue notice immediately after the reconnection of an affected area to the bulk power system has been completed. A notice issued under this subparagraph must state the time the reconnection of an affected area to the bulk power system was completed.

(E) If a TDU has issued notice under subparagraphs (A) or (C) of this paragraph, and coordination with ERCOT under paragraph (6) of this subsection results in a delay in the anticipated time of isolation or reconnection, the TDU must notify operators of affected generators and load resources of such delay.

(6) Coordination with ERCOT.

(A) TDUs. The requirements of this subparagraph apply only to energizations of TEEEF that occur outside of an energy emergency declared by ERCOT. A TDU's isolation or reconnection of load associated with an energization of TEEEF must be coordinated with ERCOT according to the following timeframes if the total amount of load at any single substation that would be isolated or reconnected exceeds 20 megawatts.

(i) For isolations of load from the bulk power system due to circumstances within a TDU's control, a TDU should coordinate with ERCOT within a period of 10 minutes.

(ii) For isolations of load from the bulk power system due to circumstances beyond a TDU's control, a TDU should coordinate with ERCOT as soon as is reasonably practicable.

(B) Affected generators and load resources.

(i) Upon receiving notice from a TDU that an affected area will be isolated from the bulk power system, an operator of an affected generator or load resource that is required by ERCOT protocols to provide status telemetry to ERCOT must, at the expected time of isolation as indicated in the TDU's notice, update its real-time status telemetry and current operating plan information to reflect that the affected generator or load resource is disconnected from the ERCOT system, is unavailable for dispatch by ERCOT, and will be unavailable for dispatch by ERCOT for the time period specified by the TDU in its notice.

(ii) Upon receiving notice from a TDU that an affected area has been reconnected to the bulk power system, the operator of any affected generator or load resource must update its real-time status telemetry and current operating plan information to reflect the appropriate status of the affected generator or load resource.

(7) A TDU's liability related to the provision of service using a TEEEF is governed by §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor-Owned Transmission and Distribution Utilities).

(8) A TDU will ensure, to the extent reasonably practicable, that:

(A) A retail distribution customer's usage during the TDU's operation of a TEEEF is excluded or removed from the electric usage reported to ERCOT for final settlement and to retail electric providers (REPs) for customer billing; and

(B) Energy generated in an area isolated from the bulk power system in accordance with this section, including any energy generated by an affected generator, is excluded or removed from the generation reported to ERCOT for final settlement purposes.

(9) During an energy emergency declared by ERCOT, the amount of any load shed by a TDU for the area operated in isolation from the bulk power system during TEEEF energization must be accounted for net of any generation in the affected area that was online and producing before the area was isolated from the bulk power system.

(10) After-action report. After each significant power outage in a TDU's service territory that meets the criteria for TEEEF energization under paragraph (1) of this subsection, a TDU that has leased TEEEF must file an after-action report with the commission. The report must be filed within 30 days from the last day of the significant power outage. The report must include, as applicable:

(A) A description of the events that resulted in the significant power outage within the TDU's service territory, including the dates and times the significant power outage began and ended;

(B) The estimated number of affected distribution customers and estimated amount of load, in megawatts, that were affected by the significant power outage in the TDU's service territory and the estimated number of which that were served by TEEEF;

(C) The estimated number and type of critical load, critical care customers or other critical infrastructure facilities as defined in §25.497 of this title, affected by the significant power outage and the estimated number that were served by TEEEF. A TDU must also include available details on the duration of service interruptions for these customers;

(D) The total nameplate generating capacity in megawatts and the total number of affected generators or load resources that were isolated from the bulk power system for TEEEF energization.

(E) A description of any TEEEF energizations, including the capacity, fuel type, connection configuration, and mobile capability of each TEEEF unit that was energized, the function each TEEEF unit was performing, the date and time each TEEEF unit was energized, and the duration that the affected area was isolated from the bulk power system;

(F) A list of TEEEF that was not energized, including the capacity, fuel type, connection configuration, and mobile capability of each TEEEF unit that was not energized and a brief summary explaining why each TEEEF unit was not energized.

(G) A description of any TEEEF units that were leased under subsection (d) of this section or utilized under a mutual assistance agreement or program. A TDU must include an explanation for the necessity of the emergency lease or utilization of the mutual assistance agreement or program;

(g) Emergency operations annex. A TDU that leases TEEEF under this section must include a detailed plan on the use of the TDU's leased TEEEF in the TDU's emergency operations plan filed with the commission, as required by §25.53 of this title (relating to Electric Service Emergency Operations Plans), that is updated, as necessary, on an ongoing basis.

(h) Eligible costs.

(1) Costs to obtain, and operate a TEEEF. Reasonable and necessary costs of leasing, and operating a TEEEF, including the present value of future payments required under the lease, are eligible for recovery under this section. A lease involving a TEEEF must be treated as a capital lease or finance lease for ratemaking purposes, regardless of its classification under generally accepted accounting principles or other accounting frameworks.

(2) Return. Reasonable and necessary costs under this section include a return on investment, including the present value of future payments required under the lease, using the rate of return on investment established in the commission's final order in a TDU's most recent comprehensive base-rate proceeding.

(i) Deferred recovery of certain eligible costs. A TDU may create a regulatory asset to defer the following for recovery in a future ratemaking proceeding:

(1) The reasonable and necessary incremental operations and maintenance expenses, not otherwise included in any of the TDU's rates; and

(2) The return, not otherwise included in any of the TDU's rates.

(j) Cost recovery. Eligible costs under this section may be recovered as follows.

(1) Ratemaking proceedings. A TDU may request recovery of eligible costs, including any deferred expenses, through a standalone TEEEF rider proceeding, a proceeding under §25.243 of this title (relating to Distribution Cost Recovery Factor (DCRF)), or in another ratemaking proceeding where it is appropriate to recover distribution invested capital and associated costs. A river authority may request recovery of eligible costs, including any deferred expenses, through a ratemaking proceeding where it is appropriate to recover distribution invested capital and associated costs or through a standalone TEEEF rider proceeding.

(A) A TDU must provide notice to REPs of the approved rates not later than the 45th day prior to the effective date of the approved.

(B) TEEEF costs must not be allocated to, or collected from, retail transmission service customers or wholesale transmission service at transmission voltage customers.

(C) Notwithstanding the provisions of §25.243 of this title, an allocation of TEEEF costs among distribution-level rate classes, based on substation-level class non-coincident peak demand, regardless of the time at which the class demand occurs, from the TDU's current or most recent base-rate proceeding, is presumed to be reasonable.

(D) TEEEF rates may not be established on a per-kilowatt-hour basis for any customer class that includes demand charges.

(E) Upon any amendment to a lease under this section that would reduce the rate of cost recovery necessary for a TEEEF, a TDU must submit an application to reflect the reduced rate of cost recovery necessary, by the earlier of three months from the lease amendment or the TDU's next DCRF proceeding.

(F) TEEEF costs must not be included in base rates. All TEEEF costs must be recovered through a single rider associated with TEEEF. A TDU with a previously established TEEEF rider may recover additional TEEEF costs by updating the existing TEEEF rider.

(G) TEEEF costs will not be reviewed for reasonableness, necessity, or prudence in a proceeding other than a base-rate proceeding, unless the presiding officer finds good cause to review them in another proceeding.

(H) In any proceeding in which TEEEF costs are reviewed for reasonableness, necessity, or prudence, the application must include the after-action reports for significant power outages during the period for which costs are being reviewed. The application must also include the leases, filed confidentially, for any leased TEEEF for which costs are being reviewed.

(I) A TDU that, prior to the effective date of this rule, received commission approval in a contested case proceeding for an amount of TEEEF generating capacity may request approval of reductions of that capacity through a subsequent standalone TEEEF rider proceeding made in accordance with this paragraph.

(2) Notice. The notice for any ratemaking proceeding in which eligible TEEEF costs are sought must specifically identify those eligible costs.

(3) Affiliate contracts. For any contract between a TDU and an affiliate, the TDU bears the burden of proof to show that the terms to the TDU were reasonable and necessary and did not exceed the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons within the same market area or having the same market conditions. In addition, all affiliate payments must comply with the requirements of PURA §36.058.

(4) Reconciliation. If TEEEF rates include any eligible costs that have not been reviewed for reasonableness, necessity, and prudence, any rates to recover any portion of those costs are temporary rates that must be reconciled in the TDU's next base-rate proceeding, including to determine whether the costs are reasonable, necessary, and prudent.

(A) In reconciling TEEEF costs, all revenues received associated with TEEEF programs, including actual rate revenues and mutual assistance reimbursements, must be applied to offset reasonable, necessary, and prudent TEEEF costs as these costs and revenues were incurred and received.

(B) A TDU must provide comprehensive testimony and workpapers supporting the reconciliation of all eligible costs and associated rate revenues as part of any base-rate proceeding application. Any amounts recovered through rates approved under this subsection that are found to have been unreasonable, unnecessary, or imprudent, plus the corresponding return, taxes, and carrying costs, must either be refunded or applied as an offset to any outstanding regulatory asset associated with eligible costs. In any proceeding in which the commission determines that a TDU has included in rates any amounts deemed unreasonable, unnecessary, or imprudent, or that the TDU has otherwise over-recovered costs, the commission may order a compliance proceeding to determine the amounts and manner of any necessary refunds to ratepayers or the proper accounting of over-recovered amounts as an offset to any outstanding regulatory assets associated with eligible costs. Carrying costs will be determined as follows:

(i) For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the TDU's base rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the same rate of return that was applied to the TDU's rate base included in base rates in effect when the over-recovery began.

(ii) For the time period beginning with the effective date of the TDU's rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the TDU's rate of return authorized in that base-rate proceeding.

(5) As part of the reconciliation of TEEEF costs, the commission may consider whether the leased TEEEF had the characteristics required to perform the functions authorized by the commission, whether the TEEEF was properly utilized to restore power during significant power outages, including appropriate pre-outage preparations such as positioning and securing fuel or the units, or any other factor relevant to the prudence or reasonableness of the TDU's procurement or operation of TEEEF.

§25.59. Long Lead-Time Facilities.

(a) Applicability. This section provides that a transmission and distribution utility (TDU) may procure, own, operate, and recover costs of long lead-time facilities. This section applies to a TDU that operates distribution facilities in the Electric Reliability Council of Texas (ERCOT) region to serve distribution customers.

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

(1) Long lead-time facilities--transmission and distribution facilities that would aid in restoring power to the TDU's distribution customers following a significant power outage and that the TDU reasonably anticipates will require at least six months to obtain. These facilities may not include energy storage equipment or facilities as described under Public Utility Regulatory Act (PURA), Chapter 35, Subchapter E.

(2) Significant power outage--an event that:

(A) causes ERCOT to order a TDU to shed load;

(B) the Texas Division of Emergency Management, ERCOT, or the executive director of the commission determines should be classified as a significant power outage; or

(C) results in a loss of electric power that:

(i) affects a significant number of a TDU's distribution customers and has lasted, or is expected to last, for at least six hours;

(ii) affects a TDU's distribution customers in an area for which the governor has issued a disaster or emergency declaration;

(iii) affects a TDU's distribution customers served by a radial transmission or distribution facility, creates a risk to public health or safety, and has lasted, or is expected to last, for at least 12 hours; or

(iv) creates a risk to public health or safety because it affects a critical infrastructure facility that serves the public such as a hospital, health care facility, law enforcement facility, fire station, or water or wastewater facility.

(c) Contracts for long lead-time facilities. A TDU may enter into contracts to procure, own, and operate long lead-time facilities. Such contractual arrangements may include cooperative agreements with another TDU or procurement subscriptions with a transmission and distribution equipment supply service company or other third party as described under this section.

(1) Cooperative agreements. A TDU may enter into a cooperative agreement with another TDU to:

(A) jointly procure, own, and operate long lead-time facilities;

(B) maintain inventories of long lead-time transmission and distribution equipment; or

(C) engage in transfers of such facilities or equipment following a significant power outage.

(2) Procurement subscriptions. A TDU may subscribe with a transmission and distribution equipment supply service to access and utilize an inventory of transmission and distribution equipment for the construction, modification, or operation of long lead-time facilities.

(d) Emergency operations annex. A TDU that procures, owns, and operates long lead-time facilities under this section must include these facilities in the TDU's emergency operations plan filed with the commission, as required by §25.53 of this title (relating to Electric Service Emergency Operations Plans), on an ongoing basis.

(e) Eligible costs.

(1) Costs to procure, own, and operate long lead-time facilities. Reasonable and necessary costs of procuring, owning, and operating long lead-time facilities, including costs incurred under a cooperative agreement or procurement subscription, are eligible for recovery under this section, to the extent these costs are not otherwise included in the TDU's rates.

(2) Return. Reasonable and necessary costs under this section include a return on investment using the rate of return on investment established in the commission's final order in the TDU's most recent comprehensive base-rate proceeding . The return may be applied beginning on the date that a long lead-time facility is procured.

(f) Deferred recovery of certain eligible costs. A TDU may create a regulatory asset to defer to a future ratemaking proceeding the recovery of incremental operations and maintenance expenses and the return, not otherwise recovered in a rate proceeding, associated with the procurement, ownership, maintenance, and operation of long lead-time facilities. These costs may be recorded, in order to be requested for recovery in a future proceeding, beginning on the date the long lead-time facility is procured.

(g) Cost recovery. Eligible costs under this section may be recovered as follows.

(1) Ratemaking proceedings.

(A) A TDU may:

(i) request recovery of eligible costs, including any deferred expenses, pertaining to distribution invested capital and its associated costs through a proceeding under §25.243 of this title (relating to Distribution Cost Recovery Factor (DCRF)), or in another ratemaking proceeding appropriate to recover distribution-invested capital and its associated costs; and

(ii) A TDU may request recovery of eligible costs under this section, including any deferred expenses, pertaining to transmission-invested capital and its associated costs through a proceeding under §25.192(h) of this title (relating to Interim Update of Transmission Rates) or in another ratemaking proceeding appropriate to recover transmission-invested capital and its associated costs.

(B) A TDU seeking cost recovery under this section must include sufficient documentation in its filing to support a determination that the facilities procured meet the definition of long lead-time facilities under subsection (b)(1) of this section.

(2) Notice. The notice for any ratemaking proceeding in which eligible costs addressed in this section are sought must specifically identify those eligible costs. Notice under this paragraph is required for all costs that have not been reconciled on or before the effective date of this rule.

(3) Affiliate contracts. For any contract between the TDU and an affiliate, the TDU bears the burden of proof that the terms to the TDU were reasonable, necessary, prudent, and did not exceed the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons within the same market area or having the same market condition. In addition, all affiliate payments must comply with the requirements of PURA §36.058.

(4) Temporary rates and reconciliation. If any rates include eligible costs that have not been reviewed for prudence, reasonableness, and necessity, the rates to recover those costs are temporary rates that must be reconciled in the TDU's next base-rate proceeding.

(A) A TDU must provide comprehensive testimony and workpapers supporting the reconciliation of all eligible costs and associated rate revenues as part of any base-rate proceeding application. Any amounts recovered through rates approved under this subsection that are found to have been unreasonable, unnecessary, or imprudent, plus the corresponding return, taxes, and carrying charges, must either be refunded or applied as an offset to any outstanding regulatory asset associated with eligible costs.

(B) In any proceeding in which the commission determines that a TDU has included in rates any amounts deemed unreasonable, unnecessary, or imprudent, or that the TDU has otherwise over-recovered costs, the commission may order a compliance proceeding to determine the amounts and manner of any necessary refunds to ratepayers or the proper accounting of over-recovered amounts as an offset to any outstanding regulatory assets associated with eligible costs. Carrying costs will be determined as follows:

(i) For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the TDU's base rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the same rate of return that was applied to the TDU's rate base included in base rates in effect when the over-recovery began.

(ii) For the time period beginning with the effective date of the TDU's rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the TDU's rate of return authorized in that base-rate proceeding.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Public Utility Commission of Texas
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TITLE 19. EDUCATION

PART 7. STATE BOARD FOR EDUCATOR CERTIFICATION

CHAPTER 229. ACCOUNTABILITY SYSTEM FOR EDUCATOR PREPARATION

The State Board for Educator Certification (SBEC) adopts amendments to 19 Texas Administrative Code (TAC) §§229.1 - 229.4, 229.6, and 229.9, concerning accountability system for educator preparation programs. The amendments to §§229.1 - 229.4, 229.6, and 229.9 are adopted without changes to the proposed text as published in the August 9, 2024 issue of the *Texas Register* (49 TexReg 5895) and will not be republished. Chapter 229 establishes the performance standards and procedures for educator preparation program (EPP) accountability. The adopted amendments provide for adjustments to the 2023-2024 *Accountability System for Educator Preparation (ASEP) Manual)*; clarify and streamline language and definitions; organize the rule text by subchapter; and include technical updates.

REASONED JUSTIFICATION: EPPs are entrusted to prepare educators for success in the classroom. Texas Education Code (TEC), §21.0443, requires EPPs to adequately prepare candidates for certification. Similarly, TEC, §21.031, requires the SBEC to ensure candidates for certification demonstrate the knowledge and skills necessary to improve the performance of the diverse student population of this state. TEC, §21.045, also requires SBEC to establish standards to govern the continuing accountability of all EPPs. The SBEC rules in 19 TAC Chapter 229 establish the process used for issuing annual accreditation ratings for all EPPs to comply with these provisions of the TEC and to ensure the highest level of educator preparation, which is codified in the SBEC Mission Statement.

Following is a description of the topics for the adopted amendments to 19 TAC Chapter 229.

Subchapter A. Accountability System for Educator Preparation Program Procedures

Adopted new Subchapter A and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future.

§229.1. General Provisions and Purpose of Accountability System for Educator Preparation Programs.

Update of ASEP Manual:

The adopted amendment to Figure: 19 TAC §229.1(c) updates the ASEP manual as follows:

Updates to the table of contents provide consistent descriptive language for the Principal Survey and Teacher Survey throughout the manual.

Updates to Chapter 1 remove the date to future updates and provide consistent descriptive language for the Principal Survey and Teacher Survey.

Updates to Chapter 3 simplify the description of included individuals to clearly align with 19 TAC §229.4(a)(1)(A). The update also removes the exception language related to the Performance Assessment for School Leaders, as starting in the 2023-2024 academic year. It is included in Indicator 1A, as prescribed by 19 TAC §229.2(27). Updates to the example also remove this exception. Finally, updates are made to the example to minimize the inclusion of test 291 and to remove 2 of the 3 examples, since it has expired and the procedure for combining the results is now rare. This provides clarity to the field about the calculations.

Updates to Chapter 4 provide consistency to how the manual refers to the Appraisal of First-Year Teachers by Administrators, including the parenthetical language "Principal Survey," which is in general usage in the field. This provides clarity to stakeholders. Further updates provide clearer language related to the inclusion criteria for teachers in the survey population, including the requirements of employment at the time of the PEIMS snapshot date and holding of their first certificate. This provides transparency to the field. The worked example is also updated to reflect these changes.

Updates to Chapter 5 replace the term "STAAR progress measure" with "STAAR Annual Growth Points" to follow the language in use in 19 TAC Figure: §97.1001(b). This provides a clear match between the ASEP manual and the data source. The updates clarify the included individuals, adding a requirement of being enrolled or finishing an EPP within five years prior to their first year employed as a certified teacher of record. This follows inclusion criteria for the principal survey and teacher survey and ensures a clear boundary for the included population. The updates also clarify the included subject areas and certificate requirements. This provides transparency as to how these calculations are conducted. The section about included assessments is updated to match 19 TAC Figure: §97.1001(b), which provides an accurate description of the data. The section about the scoring approach is updated to better describe the process used to do the calculation, based on the data that are available. The worked example is updated based on these changes.

Updates to Chapter 6 specify that beginning in the 2024-2025 academic year, certificate deactivations must meet the requirements in the newly adopted Chapter 228, Requirements for Educator Preparation Programs. This provides transparency to the field about this requirement. Updates also note the timeline for the evaluation of the new observations in adopted new 19 TAC Chapter 228, Subchapter F, Support for Candidates During Required Clinical Experiences, with the new requirements first being used in the 2025-2026 academic year. This includes a requirement that beginning in the 2025-2026 academic year, only candidates that began their clinical experiences after the effective date of the rule would be included in the evaluation. This provides EPPs the opportunity to update their practices while ensuring that the evaluation for this indicator is based on the rules that were in place for the duration of the clinical experience. Additional updates clarify that observations must occur within the date range of the clinical experience, providing clarity to the field. Updates also remove the exclusion of demographic data for indicator 4b. This exclusion is no longer needed because the data is now collected and can be used. This update increases the total amount of data used in the determination of ASEP statuses and aligns indicator 4b with the other indicators. An update to the worked example corrects the language used for clarity.

Updates to Chapter 7 provide consistency to how the manual refers to the Evaluation of Educator Preparation Programs by Teachers, including the parenthetical languages "Teacher Survey," which is in general usage in the field. This provides clarity to stakeholders. Further updates provide clearer language related to the inclusion criteria for teachers in the survey population, including the requirements of employment at the time of the PEIMS snapshot date and holding their first certificate. Updates also remove outdated language. This provides transparency to the field. The worked example is updated to reflect these changes.

Updates to Chapter 8 remove the EPP commendations for the 2023-2024 academic year. This provides a pause while Texas Education Agency (TEA) staff work with the Board and stakeholders to update the commendation system aligned with new requirements in Chapter 228.

Updates to Chapter 9 update the examples to include the language about the surveys updated earlier in the rule. This provides consistency in usage. Updates also provide an additional year for programs to make improvements on specific indicators by increasing the number of years in a row necessary for a negative value to be introduced into the Index system from two consecutive years to three consecutive years. Currently, if a program fails the same indicator for the same demographic group or at the aggregated "all" level for two years in a row, the weight assigned to the point value is -1, which has a greater impact on the overall score than missing in the first year, where the weight assigned is a 0. The update changes the timeline so that if a program were to miss in the second year, the value would also be 0, and if the program were to miss for the third year consecutively, then the negative weight would be introduced. This is aligned with discussion from the Board and recommended by stakeholders. The worked example is updated to reflect this change.

Update to Commendations

The update to §229.1(d) simplifies the language related to commendations and notes that commendations are not designated for the 2023-2024 reporting year. This provides a pause while TEA staff work with the Board and stakeholders to update the commendation system aligned with new requirements in Chapter 228.

§229.2. Definitions.

The adopted amendment to §229.2(5) "Beginning teacher" clarifies the certification status for a beginning teacher. This aligns the definition with the requirements used for the sample population for ASEP indicator 3, which is where the definition is used.

The adopted amendment to §229.2(6) "Candidate" clarifies the enrollment status for a candidate and provides a technical edit to remove a reference that is no longer used. This aligns the definition with how it is used elsewhere in the chapter.

The adopted amendment to §229.2(9) "Clinical teaching" includes a technical cross-reference edit to reflect the newly adopted Chapter 228 to change references from §228.35 to §228.2.

The adopted amendment to §229.2(13) "Cooperating teacher" aligns the wording to reflect the wording in the newly adopted Chapter 228.

The adopted amendment to §229.2(24) "Internship" includes a technical cross-reference edit to reflect the newly adopted Chapter 228 to change references from §228.35 to §228.2.

The adopted amendment to §229.2(25) "Mentor" aligns the wording to reflect the wording in the newly adopted Chapter 228.

The adopted amendment to §229.2(26) strikes the definition of "New Teacher" because it is not used in the rules. Subsequent definitions are renumbered.

The adopted amendment to §229.2(28), (renumbered to adopted §229.2(27)), "Practicum" includes a technical cross-reference edit to reflect the newly adopted Chapter 228 to change references from §228.35 to §228.2.

The adopted amendment to §229.2(30), (renumbered to adopted §229.2(29)), "Site Supervisor" aligns the wording to reflect the wording in the newly adopted Chapter 228.

§229.3. Required Submissions of Information, Surveys, and Other Data.

The adopted amendment to §229.3(a) removes "new teachers" because there is no longer a separate requirement for "new teachers" and "first-year teachers" related to data collection. The adopted amendment to §229.3(e) and (f) provides consistent language, removing the only use of "participant" in the chapter, and shifts the language from "new" teacher to "first-year" teacher since the survey requirement is now applicable to first-year teachers. This streamlines the language used in the rule and aligns the language in this section with the teacher survey population.

Subchapter B. Accountability System for Educator Preparation Accreditation Statuses

Adopted new Subchapter B and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future.

§229.4. Determination of Accreditation Status.

The adopted amendment to §229.4(a)(1)(B) strikes the exception for the Performance Assessment for School Leaders because it is now expired. The subsequent provisions are relettered.

The adopted amendment to §229.4(a)(3) replaces the term "STAAR Annual Progress Measure" with "STAAR Annual Growth Points" to follow the language in use in 19 TAC Figure: §97.1001(b). The amendment also provides the 2023-2024 academic year as a report only year, because the processes used by TEA to generate the underlying data has shifted, and a report-only year allows the Board and stakeholders to review results from this new model prior to the data being used for accountability.

The adopted amendment to §229.4(a)(4) and §229.4(a)(4)(A) removes the general reference to Chapter 228 and replaces it with the specific reference in §229.4(a)(4)(A)(1) and §229.4(a)(4)(A)(2). This provides a clear timeline for when the evaluation of observations will use the current standard and when the evaluation of the observations will use the updated standard in newly adopted 19 TAC Chapter 228, Subchapter F, with the new requirements first being used in the 2025-2026 academic year. This provides EPPs the opportunity to update their practices while ensuring that the evaluation for this indicator is based on the rules that were in place for the duration of the clinical experience.

The adopted amendment to §229.4(a)(5) updates the language from "new" teacher to "first-year" teacher since the teacher survey population has been updated to match that definition. This provides clarity and streamlines the language used in the rule.

Subchapter C. Accreditation Sanctions

Adopted new Subchapter C and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future. Section 229.5, currently in effect, is organized under new Subchapter C, but no rule changes were made.

Subchapter D. Continuing Approval Procedures

Adopted new Subchapter D and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future.

§229.6. Continuing Approval.

The adopted amendment to §229.6(a) and (b) includes a technical cross-reference edit to reflect the newly adopted Chapter 228.

Subchapter E. Review Procedures

Adopted new Subchapter E and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future. Sections 229.7 and 229.8, currently in effect, are organized under new Subchapter E, but no rule changes were made.

Subchapter F. Required Fees

Adopted new Subchapter F and title further organize the rule text and enable greater flexibility in rulemaking for the SBEC in the future.

§229.9. Fees for Educator Preparation Program Approval and Accountability.

The adopted amendment to §229.9(2) and (3) includes a technical cross-reference edit to reflect the newly adopted Chapter 228.

SUMMARY OF COMMENTS: The public comment period on the proposal began August 9, 2024, and ended September 9, 2024. The SBEC also provided an opportunity for registered oral and written comments on the proposal at the September 20, 2024, meeting's public comment period in accordance with the SBEC board operating policies and procedures. The following public comment was received on the proposal.

Comment: A representative from Texans for Special Education Reform requested that the questions on the Principal Survey relating to students with disabilities be required to be answered for every teacher, not just those indicated by the principal as having worked directly with students with disabilities. Additionally, the commenter also requested that the survey be revised to better reflect the statutory requirements of TEC, §21.0443(b).

Response: The SBEC disagrees. The rationale for the optional nature of these survey sections related to students with disabilities is to allow for flexibility to match the practical experience of new teachers in the field. Most teachers do work with students with disabilities. This is reflected in the survey data, as respondents completed the optional sections on over 80% of surveys. This response rate provides evidence that principals and teachers recognize that it is highly common that they work with students with disabilities, even outside specific assignments. Consequently, EPPs are held accountable for preparing candidates to meet the needs of students with disabilities through these surveys. Retaining the optional nature of these survey sections provides flexibility for the minority of teachers who do not work with students with disabilities.

The State Board of Education (SBOE) took no action on the review of the amendments to §§229.1 - 229.4, 229.6, and 229.9 at the November 22, 2024, SBOE meeting.

SUBCHAPTER A. ACCOUNTABILITY SYSTEM FOR EDUCATOR PREPARATION PROGRAM PROCEDURES

19 TAC §§229.1 - 229.3

STATUTORY AUTHORITY. The amendments are adopted under Texas Education Code (TEC), §21.041(a), which allows the State Board for Educator Certification (SBEC) to adopt rules as necessary for its own procedures; TEC, §21.041(b)(1), which requires the SBEC to propose rules that provide for the regulation of educators and the general administration of the TEC, Chapter 21, Subchapter B, in a manner consistent with the TEC, Chapter 21, Subchapter B; TEC, §21.041(d), which states that the SBEC may adopt a fee for the approval and renewal of approval of an EPP, for the addition of a certificate or field of certification, and to provide for the administrative cost of appropriately ensuring the accountability of EPPs; TEC, §21.043(b) and (c), which require SBEC to provide EPPs with data, as determined in coordination with stakeholders, based on information reported through the Public Education Information Management System (PEIMS) that enables an EPP to assess the impact of the program and revise the program as needed to improve; TEC, §21.0441(c) and (d), which require the SBEC to adopt rules setting certain admission requirements for EPPs; TEC, §21.0443, which states that the SBEC shall propose rules to establish standards to govern the approval or renewal of approval of EPPs and certification fields authorized to be offered by an EPP. To be eligible for approval or renewal of approval, an EPP must adequately prepare candidates for educator certification and meet the standards and requirements of the SBEC. The SBEC shall require that each EPP be reviewed for renewal of approval at least every five years. The SBEC shall adopt an evaluation process to be used in reviewing an EPP for renewal of approval; TEC, §21.045, which states that the board shall propose rules establishing standards to govern the approval and continuing accountability of all EPPs; TEC, §21.0451, which states that the SBEC shall propose rules for the sanction of EPPs that do not meet accountability standards and shall annually review the accreditation status of each EPP. The costs of technical assistance required under TEC, §21.0451(a)(2)(A), or the costs associated with the appointment of a monitor under TEC, §21.0451(a)(2)(C), shall be paid by the sponsor of the EPP; and TEC, §21.0452, which states that to assist persons interested in obtaining teaching certification in selecting an EPP and assist school districts in making staffing decisions, the SBEC shall make certain specified information regarding EPPs in this state available to the public through the SBEC's Internet website.

CROSS REFERENCE TO STATUTE. The amendments implement Texas Education Code, §§21.041(a), (b)(1), and (d); 21.043(b) and (c); 21.0441(c) and (d); 21.0443; 21.045; 21.0451; and 21.0452.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 18, 2024.

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Cristina De La Fuente-Valadez
Director, Rulemaking
State Board for Educator Certification
Effective date: January 7, 2025
Proposal publication date: August 9, 2024
For further information, please call: (512) 475-1497

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SUBCHAPTER B. ACCOUNTABILITY SYSTEM FOR EDUCATOR PREPARATION ACCREDITATION STATUSES

19 TAC §229.4

STATUTORY AUTHORITY. The amendment is adopted under Texas Education Code (TEC), §21.041(a), which allows the State Board for Educator Certification (SBEC) to adopt rules as necessary for its own procedures; TEC, §21.041(b)(1), which requires the SBEC to propose rules that provide for the regulation of educators and the general administration of the TEC, Chapter 21, Subchapter B, in a manner consistent with the TEC, Chapter 21, Subchapter B; TEC, §21.041(d), which states that the SBEC may adopt a fee for the approval and renewal of approval of an EPP, for the addition of a certificate or field of certification, and to provide for the administrative cost of appropriately ensuring the accountability of EPPs; TEC, §21.043(b) and (c), which require SBEC to provide EPPs with data, as determined in coordination with stakeholders, based on information reported through the Public Education Information Management System (PEIMS) that enables an EPP to assess the impact of the program and revise the program as needed to improve; TEC, §21.0441(c) and (d), which require the SBEC to adopt rules setting certain admission requirements for EPPs; TEC, §21.0443, which states that the SBEC shall propose rules to establish standards to govern the approval or renewal of approval of EPPs and certification fields authorized to be offered by an EPP. To be eligible for approval or renewal of approval, an EPP must adequately prepare candidates for educator certification and meet the standards and requirements of the SBEC. The SBEC shall require that each EPP be reviewed for renewal of approval at least every five years. The SBEC shall adopt an evaluation process to be used in reviewing an EPP for renewal of approval; TEC, §21.045, which states that the board shall propose rules establishing standards to govern the approval and continuing accountability of all EPPs; TEC, §21.0451, which states that the SBEC shall propose rules for the sanction of EPPs that do not meet accountability standards and shall annually review the accreditation status of each EPP. The costs of technical assistance required under TEC, §21.0451(a)(2)(A), or the costs associated with the appointment of a monitor under TEC, §21.0451(a)(2)(C), shall be paid by the sponsor of the EPP; and TEC, §21.0452, which states that to assist persons interested in obtaining teaching certification in selecting an EPP and assist school districts in making staffing decisions, the SBEC shall make certain specified information regarding EPPs in this state available to the public through the SBEC's Internet website.

CROSS REFERENCE TO STATUTE. The amendment implements Texas Education Code, §§21.041(a), (b)(1), and (d); 21.043(b) and (c); 21.0441(c) and (d); 21.0443; 21.045; 21.0451; and 21.0452.

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SUBCHAPTER D. CONTINUING APPROVAL PROCEDURES

19 TAC §229.6

STATUTORY AUTHORITY. The amendment is adopted under Texas Education Code (TEC), §21.041(a), which allows the State Board for Educator Certification (SBEC) to adopt rules as necessary for its own procedures; TEC, §21.041(b)(1), which requires the SBEC to propose rules that provide for the regulation of educators and the general administration of the TEC, Chapter 21, Subchapter B, in a manner consistent with the TEC, Chapter 21, Subchapter B; TEC, §21.041(d), which states that the SBEC may adopt a fee for the approval and renewal of approval of an EPP, for the addition of a certificate or field of certification, and to provide for the administrative cost of appropriately ensuring the accountability of EPPs; TEC, §21.043(b) and (c), which require SBEC to provide EPPs with data, as determined in coordination with stakeholders, based on information reported through the Public Education Information Management System (PEIMS) that enables an EPP to assess the impact of the program and revise the program as needed to improve; TEC, §21.0441(c) and (d), which require the SBEC to adopt rules setting certain admission requirements for EPPs; TEC, §21.0443, which states that the SBEC shall propose rules to establish standards to govern the approval or renewal of approval of EPPs and certification fields authorized to be offered by an EPP. To be eligible for approval or renewal of approval, an EPP must adequately prepare candidates for educator certification and meet the standards and requirements of the SBEC.

The SBEC shall require that each EPP be reviewed for renewal of approval at least every five years. The SBEC shall adopt an evaluation process to be used in reviewing an EPP for renewal of approval; TEC, §21.045, which states that the board shall propose rules establishing standards to govern the approval and continuing accountability of all EPPs; TEC, §21.0451, which states that the SBEC shall propose rules for the sanction of EPPs that do not meet accountability standards and shall annually review the accreditation status of each EPP. The costs of technical assistance required under TEC, §21.0451(a)(2)(A), or the costs associated with the appointment of a monitor under TEC, §21.0451(a)(2)(C), shall be paid by the sponsor of the EPP; and TEC, §21.0452, which states that to assist persons interested in obtaining teaching certification in selecting an EPP and assist school districts in making staffing decisions, the SBEC shall make certain specified information regarding EPPs in this state available to the public through the SBEC's Internet website.

CROSS REFERENCE TO STATUTE. The amendment implements Texas Education Code, §§21.041(a), (b)(1), and (d); 21.043(b) and (c); 21.0441(c) and (d); 21.0443; 21.045; 21.0451; and 21.0452.

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SUBCHAPTER F. REQUIRED FEES

19 TAC §229.9

STATUTORY AUTHORITY. The amendment is adopted under Texas Education Code (TEC), §21.041(a), which allows the State Board for Educator Certification (SBEC) to adopt rules as necessary for its own procedures; TEC, §21.041(b)(1), which requires the SBEC to propose rules that provide for the regulation of educators and the general administration of the TEC, Chapter 21, Subchapter B, in a manner consistent with the TEC, Chapter 21, Subchapter B; TEC, §21.041(d), which states that the SBEC may adopt a fee for the approval and renewal of approval of an EPP, for the addition of a certificate or field of certification, and to provide for the administrative cost of appropriately ensuring the accountability of EPPs; TEC, §21.043(b) and (c), which require SBEC to provide EPPs with data, as determined in coordination with stakeholders, based on information reported through the Public Education Information Management System (PEIMS) that enables an EPP to assess the impact of the program and revise the program as needed to improve; TEC, §21.0441(c) and (d), which require the SBEC to adopt rules setting certain admission requirements for EPPs; TEC, §21.0443, which states that the SBEC shall propose rules to establish standards to govern the approval or renewal of approval of EPPs and certification fields authorized to be offered by an EPP. To be eligible for approval or renewal of approval, an EPP must adequately prepare candidates for educator certification and meet the standards and requirements of the SBEC. The SBEC shall require that each EPP be reviewed for renewal of approval at least every five years. The SBEC shall adopt an evaluation process to be used in reviewing an EPP for renewal of approval; TEC, §21.045, which states that the board shall propose rules establishing standards to govern the approval and continuing accountability of all EPPs; TEC, §21.0451, which states that the SBEC shall propose rules for the sanction of EPPs that do not meet accountability standards and shall annually review the accreditation status of each EPP. The costs of technical assistance required under TEC, §21.0451(a)(2)(A), or the costs associated with the appointment of a monitor under TEC, §21.0451(a)(2)(C), shall be paid by the sponsor of the EPP; and TEC, §21.0452, which states that to assist persons interested in obtaining teaching certification in selecting an EPP and assist school districts in making staffing decisions, the SBEC shall make certain specified information regarding EPPs in this state available to the public through the SBEC's Internet website.

CROSS REFERENCE TO STATUTE. The amendment implements Texas Education Code, §§21.041(a), (b)(1), and (d); 21.043(b) and (c); 21.0441(c) and (d); 21.0443; 21.045; 21.0451; and 21.0452.

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CHAPTER 230. PROFESSIONAL EDUCATOR PREPARATION AND CERTIFICATION

SUBCHAPTER B. GENERAL CERTIFICATION REQUIREMENTS

19 TAC §230.11

The State Board for Educator Certification (SBEC) adopts an amendment to 19 Texas Administrative Code (TAC) §230.11, concerning professional educator preparation and certification. The amendment to §230.11 is adopted without changes to the proposed text as published in the August 9, 2024 issue of the *Texas Register* (49 TexReg 5904) and will not be republished. The adopted amendment expands the options for demonstrating English language proficiency (ELP).

REASONED JUSTIFICATION: At the February 2024 SBEC meeting, Texas Education Agency (TEA) staff provided the Board with an overview of the history of the ELP requirement and confirmed that regardless of the pathway to certification in

Texas, demonstration of ELP is required for all candidates. TEA staff also posed key questions for the Board's consideration regarding current requirements in rule and possible updates for the demonstration of ELP. TEA staff anchored the conversation with the Board around required performance on the Test of English as a Foreign Language internet-Based Test (TOEFL-iBT), the list of countries approved by the SBEC to satisfy demonstration of ELP, the addition of U.S. territories to exempt individuals from the ELP requirement, and the potential use of standard certification obtained in another state by individuals licensed to teach in other countries.

At the April 2024 SBEC meeting, TEA staff provided a follow-up discussion item, including recommendations for amendments to 19 TAC Chapter 230 to be presented for consideration and action by the Board at the July SBEC meeting. The Board provided final direction on how to move forward with the proposal.

The following is a description of the adopted amendment.

Adopted Amendment to Required Performance on the TOEFL-iBT

The adopted amendment to §230.11(b)(5)(B) updates TOEFL-iBT score requirements from a specific score for each of the four sections (24 for Speaking, 22 for Listening, 22 for Reading, and 21 for Writing) to any score that falls within the range identified for performance at the High-Intermediate Level for all four sections of the test.

Adopted Amendment Related to U.S. Territories and the ELP Requirement

Adopted new §230.11(b)(5)(A) adds the phrase, "or one of its territories," to allow degrees obtained in the U.S. territories to also count toward meeting the ELP requirement.

Adopted Amendment to Add Countries to the List Approved by the SBEC for Exemption from the ELP Requirement

The adopted amendment to Figure: 19 TAC §230.11(b)(5)(C) adds Cameroon, Kenya, Philippines, South Africa, Uganda, Zambia, and Zimbabwe to the list of countries approved for exemption from the ELP requirement and strikes American Samoa to align with adopted changes that incorporate all U.S. territories in meeting the requirement.

Adopted Amendment to Include an Additional Option to Meet the ELP Requirement

Adopted new §230.11(b)(5)(D) allows an individual applying for the out-of-country credentials review who also holds a standard certificate issued in another state where exams were taken and passed to be eligible for consideration of exemption from ELP requirements.

SUMMARY OF COMMENTS: The public comment period on the proposal began August 9, 2024, and ended September 9, 2024. The SBEC also provided an opportunity for registered oral and written comments on the proposal at the September 20, 2024 meeting's public comment period in accordance with the SBEC board operating policies and procedures. No public comments were received on the proposal.

The State Board of Education (SBOE) took no action on the review of the amendment to §230.11 at the November 22, 2024 SBOE meeting.

STATUTORY AUTHORITY. The amendment is adopted under Texas Education Code (TEC), §21.003(a), which states that a person may not be employed as a teacher, teacher intern or teacher trainee, librarian, educational aide, administrator, educational diagnostician, or school counselor by a school district unless the person holds an appropriate certificate or permit issued as provided by TEC, Chapter 21, Subchapter B; TEC, §21.031, which authorizes the State Board for Educator Certification (SBEC) to regulate and oversee all aspects of the certification, continuing education, and standards of conduct of public school educators; TEC, §21.041(b)(1), (2), and (4), which require the SBEC to propose rules that provide for the regulation of educators and the general administration of the TEC, Chapter 21, Subchapter B, in a manner consistent with TEC, Chapter 21, Subchapter B, specify the classes of educator certificates to be issued, including emergency certificates, and specify the requirements for the issuance and renewal of an educator certificate; and TEC, §21.041(b)(5), which requires the SBEC to propose rules that provide for the issuance of an educator certificate to a person who holds a similar certificate issued by another state or foreign country, subject to TEC, §21.052.

CROSS REFERENCE TO STATUTE. The amendment implements Texas Education Code, §§21.003(a), 21.031, and 21.041(b)(1), (2), (4), and (5).

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Cristina De La Fuente-Valadez
Director, Rulemaking
State Board for Educator Certification
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For further information, please call: (512) 475-1497

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TITLE 22. EXAMINING BOARDS

PART 6. TEXAS BOARD OF PROFESSIONAL ENGINEERS AND LAND SURVEYORS

CHAPTER 131. ORGANIZATION AND ADMINISTRATION

SUBCHAPTER A. SCOPE AND DEFINITIONS

22 TAC §131.2

The Texas Board of Professional Engineers and Land Surveyors (Board) adopts amendments to 22 Texas Administrative Code, Chapter 131, regarding the licensing of professional engineers, and specifically §131.2, relating to Definitions. Amendments to 22 Texas Administrative Code, Chapter §131.2 are adopted without changes to the proposed text as published in the July 12, 2024 issue of the *Texas Register* (49 TexReg 4990). The rule will not be republished.

REASONED JUSTIFICATION FOR THE RULE ADOPTION

The adopted amendments updates the name of one of the accrediting agencies. The North Central Association was dissolved in 2014 and replaced by the Higher Learning Commission (HLC).

REQUEST FOR PUBLIC COMMENT

Pursuant to §2001.029 of the Texas Government Code, the Board gave all interested persons a reasonable opportunity to provide oral and/or written commentary concerning the adoption of the rules. The public comment period began on July 12, 2024, and ended August 11, 2024. The Board received no comments from the public.

STATUTORY AUTHORITY

The amendments are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 18, 2024.

TRD-202406091

Lance Kinney

Executive Director

Texas Board of Professional Engineers and Land Surveyors

Effective date: January 7, 2025

Proposal publication date: July 12, 2024

For further information, please call: (512) 440-7723

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CHAPTER 133. LICENSING FOR ENGINEERS

The Texas Board of Professional Engineers and Land Surveyors (Board) adopts amendments to 22 Texas Administrative Code, Chapter 133, regarding the licensing of professional engineers. The proposed amendments are specifically to §133.31, relating to Educational Requirements for Applicants, §133.43, relating to Experience Evaluations, §133.53, relating to Reference Statements, and §133.67, relating to Examinations on the Principles and Practice of Engineering. The amendments to §§133.31, 133.43, 133.53, and 133.67 are adopted without changes to the proposed text as published in the July 12, 2024, issue of the *Texas Register* (49 TexReg 4992). The rules will not be republished.

REASONED JUSTIFICATION FOR THE RULE ADOPTION

The rules under 22 Texas Administrative Code, Chapter 133 implement Texas Occupations Code, Chapter 1001, the Texas Engineering Practice Act. The adopted amendments address the Board's ability to evaluate education credentials, consider experience of applicants, how the experience is verified by references, how applicants take exams, and qualifications needed to waive exams.

The amendments to §133.31 remove language that is no longer used by the Board when evaluating education credentials of applicants. The amendments also include non-substantive grammatical changes to the rule title.

The amendments to §133.43 clarify when a year of experience credit may be granted for post-baccalaureate degree. The amendments clarify that experience gained as part of an undergraduate or graduate education is not able to be used for experience credit. The amendments clarify that a calendar period claimed as surveying experience cannot also be claimed for engineering experience. Companion amendments to Chapter 134 establish rules to clarify that a calendar period claimed as engineering experience cannot also be claimed as surveying experience.

The amendments to §133.53 expand the manner the Board can receive reference statements. The practice of only accepting reference statements that have been sealed in an envelope with a signature across the flap is not the only way to convey the statements securely. The amendments are broad to allow different forms of transmittal, especially electronically (via email or electronically uploading the document to a secure location).

The amendments to §133.67 expand the manner applicants are qualified to take exams. The amendments remove a limitation on the maximum number of exams applicants may take and allow applicants who are approved to take the Principles and Practice of Engineering exam the ability to take the exam until passing. Companion amendments to Chapter 134 establish the same criteria for surveyors taking the Principles and Practice of Surveying exam.

REQUEST FOR PUBLIC COMMENT

Pursuant to §2001.029 of the Texas Government Code, the Board gave all interested persons a reasonable opportunity to provide oral and/or written commentary concerning the adoption of the rules. The public comment period began on July 12, 2024, and ended August 11, 2024. The Board received one comment from an individual.

Comment summary: Alternative wording was suggested in §§133.31 and 133.53 that did not materially change the amendments. Additional commentary was provided on areas of the sections that had no proposed changes

Board Response: The Board appreciates the comments. After consideration, no changes to the amendments are being made in response to the comment.

SUBCHAPTER D. EDUCATION

22 TAC §133.31

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state.

No other codes, articles, or statutes are affected by this adoption.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 18, 2024.

TRD-202406092

Lance Kinney
Executive Director
Texas Board of Professional Engineers and Land Surveyors
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Proposal publication date: July 12, 2024
For further information, please call: (512) 440-7723

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SUBCHAPTER E. EXPERIENCE

22 TAC §133.43

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state.

No other codes, articles, or statutes are affected by this adoption.

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SUBCHAPTER F. REFERENCE DOCUMENTATION

22 TAC §133.53

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state.

No other codes, articles, or statutes are affected by this adoption.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER G. EXAMINATIONS

22 TAC §133.67

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state.

No other codes, articles, or statutes are affected by this adoption.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 134. LICENSING, REGISTRATION, AND CERTIFICATION FOR SURVEYORS

The Texas Board of Professional Engineers and Land Surveyors (Board) adopts amendments to 22 Texas Administrative Code, Chapter 134, regarding the licensing, registration, and certification for surveyors. The adopted amendments are specifically to §134.25, relating to Applications from Out-Of-State Registration Holders, §134.43, relating to Experience Evaluations, §134.53, relating to Reference Statements, §134.67, relating to Examinations on the Principles and Practice of Surveying, and §134.68, relating to Licensed State Land Surveyor Examination, regarding the licensing, registration, and certification for surveyors. The amendments to §§134.25, 134.43, 134.53, 134.67, and 133.68 are adopted without changes to the proposed published text as published in the July 12, 2024, issue of the *Texas Register* (49 TexReg 4998). The rules will not be republished.

REASONED JUSTIFICATION FOR THE RULE ADOPTION

The adopted amendments address the Board's ability to evaluate credentials of out-of-state registration holders, consider experience of applicants, how the experience is verified by references, how applicants take exams, and fees associated with exams administered by the Board.

The amendments to §134.25 require reciprocal applicants to meet current licensing requirements and take the Texas Specific Surveying Exam for registration. Reciprocal applicants can currently apply without meeting current licensing requirements, such as education, if their initial out-of-state licensure occurred at a time when such requirements were not in place. Another change makes it clear that reciprocal applicants must take the Texas Specific Surveying Exam for registration in Texas.

The amendments to §134.43 clarify that a calendar period claimed as engineering experience cannot also be claimed for surveying experience. Companion amendments to Chapter 133 establish rules to clarify that a calendar period claimed as surveying experience cannot also be claimed as engineering experience.

The amendments to §134.53 expand the manner the Board can receive reference statements. The practice of only accepting reference statements that have been sealed in an envelope with a signature across the flap is not the only way to convey the statements securely. The amendments are broad to allow different forms of transmittal, especially electronically (via email or electronically uploading the document to a secure location).

The amendments to §134.67 expand the manner applicants are qualified to take exams. The amendments remove a limitation on the maximum number of exams applicants may take and allow applicants who are approved to take the Principles and Practice of Surveying exam the ability to take the exam until the exam is passed. A limit on the number of times the Texas Specific Surveying Exam (TSSE) may be taken before re-applying will be kept in place. Companion amendments to Chapter 133 establish the same criteria for engineers taking the Principles and Practice of Engineering exam. The amendments also clarify that TSSE exam fee will be waived in accordance with Texas Occupations Code Chapter 55.

The amendments to §134.68 clarify that Licensed State Land Surveyor exam fee will be waived in accordance with Texas Occupations Code Chapter 55.

REQUEST FOR PUBLIC COMMENT

Pursuant to §2001.029 of the Texas Government Code, the Board gave all interested persons a reasonable opportunity to provide oral and/or written commentary concerning the adoption of the rules. The public comment period began on July 12, 2024, and ended August 11, 2024. The Board received no comments from the public.

SUBCHAPTER C. LAND SURVEYOR APPLICATION REQUIREMENTS

22 TAC §134.25

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state. No other codes, articles, or statutes are affected by this proposal.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Lance Kinney
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SUBCHAPTER E. EXPERIENCE

22 TAC §134.43

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state. No other codes, articles, or statutes are affected by this proposal.

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SUBCHAPTER F. REFERENCE DOCUMENTATION

22 TAC §134.53

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state. No other codes, articles, or statutes are affected by this proposal.

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SUBCHAPTER G. EXAMINATIONS

22 TAC §134.67, §134.68

STATUTORY AUTHORITY

The rules are adopted pursuant to Texas Occupations Code §§1001.201 and 1001.202, which authorize the Board to regulate engineering and land surveying and make and enforce all rules and regulations and bylaws consistent with the Act as necessary for the performance of its duties, the governance of its own proceedings, and the regulation of the practices of engineering and land surveying in this state. No other codes, articles, or statutes are affected by this proposal.

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TITLE 26. HEALTH AND HUMAN SERVICES

PART 1. HEALTH AND HUMAN SERVICES COMMISSION

CHAPTER 568. STANDARDS OF CARE AND TREATMENT IN PSYCHIATRIC HOSPITALS

SUBCHAPTER C. EMERGENCY TREATMENTS

26 TAC §568.42

The Texas Health and Human Services Commission (HHSC) adopts new §568.42, concerning Responding to a Psychiatric Emergency.

New §568.42 is adopted with changes to the proposed text as published in the July 19, 2024, issue of the *Texas Register* (49 TexReg 5308). This rule will be republished. HHSC withdraws the proposed amendment to §568.22.

BACKGROUND AND JUSTIFICATION

The new section is necessary to increase consistency in emergency medication monitoring requirements between state rules and federal Centers for Medicare & Medicaid Services (CMS) Conditions of Participation for psychiatric hospitals.

COMMENTS

The 31-day comment period ended August 19, 2024.

During this period, HHSC received comments regarding the proposed new rule from four commenters, including Texas Hospital Association (THA), Texas Association of Behavioral Health Systems (TABHS), Disability Rights Texas (DRTx), and Hill Country MHDD Centers. A summary of comments relating to the rule and HHSC's responses follows.

Comment: THA stated it supports increased consistency in emergency medication monitoring requirements between state rules and CMS Conditions of Participation and offered suggestions, which are described in a subsequent comment. THA stated it hoped its comments would improve the rule and minimize operational impacts to hospitals.

Response: HHSC acknowledges this comment.

Comment: THA stated §568.42 will have significant operational impacts on facilities and requested HHSC provide enough time for facilities to implement changes to comply with the rule. THA expressed that additional time for implementation would ease the administrative burden and allow the rule's safe implementation without adverse consequences for patients.

Response: HHSC acknowledges this comment. HHSC notes CMS-certified facilities are already expected to comply with similar CMS Conditions of Participation. HHSC will work with facilities to ensure they are compliant after the rule's effective date.

Comment: TABHS stated its member hospitals already comply with the psychoactive medication requirements described by §568.42.

Response: HHSC acknowledges this comment.

Comment: DRTx recommended HHSC revise §568.42(a)(1) to add language stating an emergency psychoactive medication "is not used as a restriction to manage the patient's behavior, restrict the patient's freedom of movement, and is not a standard treatment or dosage for the patient's condition" to align with the CMS Conditions of Participation at Code of Federal Regulations Title 42 §482.13(e)(1)(i)(B) and the CMS interpretive guidelines for this regulation.

Response: HHSC declines to revise §568.42(a)(1) because emergency psychoactive medications as allowed by this rule are to stop an emergency behavioral issue.

Comment: THA requested HHSC amend §568.42(a)(2) to clarify a psychiatric emergency is when it is necessary to administer medication without the patient's consent. THA stated hospitals already monitor a patient according to the proposed rule after the patient receives emergency psychoactive medication, but that monitoring a patient according to the proposed rule when medication is given voluntarily and with the patient's consent is not necessary.

Response: HHSC declines to revise §568.42(a)(2) because the definition of psychiatric emergency is consistent with Texas Health and Safety Code (THSC) §576.025(g) and §574.101(2).

Comment: DRTx recommends HHSC revise §568.42(a) by adding the definition of the term "imminent" from 25 TAC §414.403(2).

Response: HHSC declines to revise §568.42(a) because the common meaning of "imminent" is sufficient for the purposes of this rule.

Comment: DRTx recommended HHSC revise the definition of psychiatric emergency at §568.42(a)(2) to align more closely with the definition at 25 TAC §414.403(9).

Response: HHSC declines to revise §568.42(a)(2) because the definition of psychiatric emergency is consistent with THSC §576.025(g) and §574.101(2).

Comment: THA requested HHSC amend §568.42(a)(3)(E)-(F) to remove stimulant, sedative, hypnotics, and other sleep-promoting drugs from the list of emergency medications. THA stated these medications are inappropriate in a psychiatric emergency medication situation.

Response: HHSC declines to revise §568.42(a)(3)(E)-(F) because the language is consistent with THSC §576.025(g) and §574.101(3).

Comment: THA expressed concern about §568.42(b), which restricts the ordering of emergency medication orders to physicians. THA stated only allowing physicians to order emergency medications could slow down treatment in emergencies, risking more harm to patients and staff. THA noted advanced practice nurses and physician assistants are authorized by law to order these medications under an appropriate physician delegation. THA expressed concern that the language misinterprets 25 TAC §414.410, which THA noted is incorrectly cited as 25 TAC §414.41 in the proposed rule, and contradicts the CMS Conditions of Participation, which allow other licensed practitioners, not just physicians, to order emergency medications if state law and hospital policy allow it. THA recommended changing §568.42(b) to allow advanced practice nurses and physician assistants to order emergency medications as their licenses and state law allow to ensure patients get the care they need without unnecessary delays.

Hill Country MHDD also commented on §568.42(b) and stated a nurse practitioner should be allowed to give the order under §568.42(b) because the prescriptive authority agreement between a physician and nurse practitioner allows a nurse practitioner to prescribe controlled substances and dangerous drugs.

Response: HHSC revises §568.42(b) to correct the typographical error to the reference of 25 TAC §414.410. HHSC declines to further revise §568.42(b) as requested because this subsection aligns with 25 TAC §414.410(b) and there are health and safety concerns with allowing a nurse practitioner or physician assistant to give orders under this subsection. In an emergency imminent risk situation, a physician cannot review a nurse practitioner's or physician assistant's decision promptly enough, and the physician has training to decide the appropriate medication to administer. Further, 25 TAC §415.260(b) requires a physician to initiate a restraint or seclusion, so it is the physician's decision to determine whether restraint or seclusion or an emergency psychoactive medication is appropriate to the situation.

Comment: DRTx recommended adding language to §568.42(b) to require either the patient's or patient's legally authorized representative's consent. DRTx also questioned if 25 TAC §414.41 referred to §414.410 and stated it would be more advisable to incorporate the necessary language into this rule since rules often move.

Response: HHSC revises §568.42(b) to correct the typographical error to the reference of 25 TAC §414.410. HHSC declines to further revise §568.42(b) as requested because the suggestions are redundant.

Comment: DRTx recommended HHSC revise §568.42 to add a new subsection (c) to clarify a physician's order for emergency psychoactive medication must only address the immediate psychiatric emergency and cannot be to justify concurrent personal restraints or administration of psychoactive medication for subsequent psychiatric emergencies. DRTx stated this language will ensure a physician will give a separate order if another emergency intervention is necessary before or after administration of the emergency psychoactive medication.

Response: HHSC declines to revise §568.42 because HHSC does not have the authority to determine a physician's practice of medicine.

Comment: DRTx recommended HHSC add language to §568.42(c) to state the treating physician may issue the emergency psychoactive medication order only if there is an existing psychoactive emergency and suggested HHSC add legally authorized representative's consent in addition to patient consent.

Response: HHSC declines to revise 568.42(c) because the additional language is unnecessary since the definition of emergency psychoactive medication states that the medication is only administered during a psychiatric emergency. HHSC declines to revise §568.42(c) to add legally authorized representative because it is redundant.

Comment: DRTx commented that the policies and procedures listed under §568.42(e) do not include the process for determining staff competency or language about re-training staff. DRTx recommended adding a requirement for a re-occurring training and competency test.

Response: HHSC declines to revise §568.42(e) because the requirements regarding training competency are located at §568.121 and 26 TAC §301.331(a)(4).

Comment: DRTx stated the knowledge of the side effects of psychoactive medication or any contraindications should be included in the training under §568.42(e)(1).

Response: HHSC declines to revise §568.42(e)(1) because knowledge of psychoactive medications implies knowledge of side effects and contraindications.

Comment: DRTx requested HHSC clarify what "safe and appropriate" administration means under §568.42(e)(2).

Response: HHSC revises §568.42(e)(2) to clarify "safe and appropriate" is in accordance with hospital policy. HHSC also revised subsections (d) and (e)(2) to add "monitoring," added "and appropriate" to subsection (d), and added "and duration" and "to ensure the health and safety of the patient" to (d)(3).

Comment: Hill Country MHDD commented on §568.42(f) and stated examining a person within one hour is the standard for restraint and seclusion, but administering psychoactive medication in a psychiatric emergency should not require this level of monitoring and documentation because it is a different situation. Hill Country MHDD noted that 25 TAC §414.410 includes this distinction.

Response: HHSC declines to revise §568.42(f) because of health and safety concerns and to align with the CMS Conditions of Participation.

Comment: DRTx requested HHSC include a definition for "other licensed practitioner" at §568.42(f).

Response: HHSC revises §568.42(d) by adding new paragraph (4) under subsection (d) to require the hospital's policies and procedures identify the licensed practitioners authorized to examine the patient under subsection (f).

Comment: DRTx requested HHSC clarify §568.42(f)(4) because emergency medication should not require the patient to withdraw because it is a one-time administration, so DRTx was unclear as to why an emergency psychoactive medication would need to be safely discontinued.

Response: HHSC revises §568.42(f)(4) to clarify the practitioner under this subsection shall evaluate and document whether to return to or modify the patient's plan of care.

Comment: DRTx recommended adding language to §568.42(g) regarding a process of documenting completion of the training, require a standardized competency evaluation, and requirements for maintaining competency through re-training and re-assessment.

Response: HHSC revises §568.42(g) to require the practitioner to receive training and demonstrate competency in the areas listed under this subsection.

Comment: DRTx recommended HHSC add language to §568.42(i) to ensure the evaluation findings describe specific behaviors that the individual exhibited to create the psychiatric emergency and demonstrate the clinical necessity of the emergency psychoactive medication used to treat the behaviors.

Response: HHSC revises §568.42(i) to change "and" to "or" and remove "as applicable" in paragraph (1) of this subsection.

Comment: DRTX recommended HHSC adding language from 25 TAC §414.410(f) to §568.42(i)(6) to ensure that a facility does not use the designation of a psychiatric emergency inappropriately to circumvent obtaining consent or applying a court order for administering psychoactive medication.

Response: HHSC declines to revise §568.42(i)(6) because in an emergency situation consent is not required. HHSC notes that facilities are required to comply with 25 TAC §414.10(f).

HHSC also revised §568.42(a)(1) to clarify emergency psychoactive medications are medications that create an immediate effect on the central nervous system to ensure staff do not use oral medications.

STATUTORY AUTHORITY

The new section is adopted under Texas Government Code §531.0055, which provides that the Executive Commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services agencies, and THSC §577.010, which requires that the Executive Commissioner of HHSC adopt rules and standards the Executive Commissioner considers necessary and appropriate to ensure the proper care and treatment of patients in a private mental hospital or mental health facility required to obtain a license under THSC Chapter 577.

§568.42. Responding to a Psychiatric Emergency.

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

(1) Emergency psychoactive medication--A psychoactive medication administered to a patient in a psychiatric emergency that is used to exercise an immediate effect on the central nervous system.

(2) Psychiatric emergency--A situation in which it is immediately necessary to administer medication to a patient to prevent:

(A) imminent probable death or substantial bodily harm to the patient because the patient:

(i) overtly or continually is threatening or attempting to commit suicide or serious bodily harm; or

(ii) is behaving in a manner that indicates that the patient is unable to satisfy the patient's need for nourishment, essential medical care, or self-protection; or

(B) imminent physical or emotional harm to another because of threats, attempts, or other acts the patient overtly or continually makes or commits.

(3) Psychoactive medication--A medication prescribed for the treatment of symptoms of psychosis or other severe mental or emotional disorders and that is used to exercise an effect on the central nervous system to influence and modify behavior, cognition, or affective state when treating the symptoms of mental illness. "Psychoactive medication" includes the following categories when used as described in this section:

(A) antipsychotics or neuroleptics;

(B) antidepressants;

(C) agents for control of mania or depression;

(D) antianxiety agents;

(E) sedatives, hypnotics, or other sleep-promoting drugs; and

(F) psychomotor stimulants.

(b) In accordance with 25 TAC §414.410 (relating to Psychiatric Emergencies), only a treating physician may issue an order to administer emergency psychoactive medication without a patient's consent.

(c) A treating physician may only issue an order to administer emergency psychoactive medication without a patient's consent when less restrictive interventions are determined ineffective to protect the patient or others from harm.

(d) A hospital shall adopt, implement, and enforce written policies and procedures to ensure safe and appropriate administration and monitoring of an emergency psychoactive medication. These policies and procedures shall:

(1) identify the staff members authorized to administer an emergency psychoactive medication;

(2) identify the psychoactive medications permitted and approved by the hospital for administration in a psychiatric emergency;

(3) prescribe how and with what frequency and duration a staff member shall monitor a patient who has received an emergency psychoactive medication to ensure the health and safety of the patient, in addition to the in-person evaluation conducted as required by subsection (f) of this section;

(4) identify the licensed practitioners authorized to examine the patient as required by subsection (f) of this section; and

(5) ensure staff members follow all monitoring and evaluation requirements under this section and all hospital policies and procedures regarding administration of an emergency psychoactive medication each time a patient receives a separate dose of an emergency psychoactive medication.

(e) Staff members authorized by the hospital's policies and procedures to administer an emergency psychoactive medication shall receive training on and demonstrate competency in the following:

(1) knowledge of the psychoactive medications permitted and approved by the hospital for administration in a psychiatric emergency;

(2) safe and appropriate administration and monitoring of an emergency psychoactive medication per hospital policies and procedures as required by subsection (d) of this section; and

(3) management of emergency medical conditions in accordance with the hospital's policies and procedures and other applicable requirements for:

(A) obtaining emergency medical assistance; and

(B) obtaining training in and using techniques for cardiopulmonary respiration and airway obstruction removal.

(f) When a staff member administers a psychoactive medication to a patient experiencing a psychiatric emergency, a physician, other licensed practitioner, or registered nurse trained in accordance with the requirements specified in subsection (g) of this section shall examine the patient in person within one hour after the administration of the psychoactive medication to evaluate and document in the patient's clinical record:

(1) the patient's immediate situation;

(2) the patient's reaction to the medication;

(3) the patient's medical and behavioral condition; and

(4) whether to return to or modify the patient's plan of care.

(g) A physician, other licensed practitioner, or registered nurse who conducts the in-person evaluation specified in subsection (f) of this section shall receive training and demonstrate competency in the following:

(1) techniques identifying staff member and patient behaviors, events, and environmental factors that may trigger a psychiatric emergency;

(2) use of nonphysical intervention skills;

(3) choosing the least restrictive intervention based on an individualized assessment of the patient's medical or behavioral status or condition;

(4) safe administration of emergency psychoactive medications and how to recognize and respond to signs of physical and psychological distress;

(5) clinical identification of specific behavioral changes indicating the psychiatric emergency's conclusion;

(6) monitoring the physical and psychological well-being of the patient who has received an emergency psychoactive medication, including the patient's respiratory and circulatory status, vital signs, and any special requirements specified by hospital policy associated with conducting the in-person evaluation; and

(7) the use of first aid techniques and certification in the use of cardiopulmonary resuscitation, including required periodic recertification.

(h) If a trained registered nurse conducts the in-person evaluation specified in subsection (f) of this section, the trained registered nurse shall consult the attending physician or other licensed practitioner responsible for the patient's care as soon as possible after completing the evaluation.

(i) The physician or other licensed practitioner responsible for the patient's care shall document in the patient's clinical record in specific medical and behavioral terms:

(1) the information required by 25 TAC §414.410(b) (relating to Psychiatric Emergencies);

(2) the evaluation findings specified in subsection (f)(1) - (4) of this section;

(3) a description of the patient's behavior and the emergency psychoactive medication used;

(4) alternatives or other less restrictive interventions attempted, as applicable;

(5) the patient's condition or symptoms warranting the emergency psychoactive medication; and

(6) the patient's response to the emergency psychoactive medication, including the rationale for continued use of the medication.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Karen Ray
Chief Counsel
Health and Human Services Commission
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For further information, please call: (512) 834-4591

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TITLE 28. INSURANCE

PART 1. TEXAS DEPARTMENT OF INSURANCE

CHAPTER 5. PROPERTY AND CASUALTY INSURANCE

SUBCHAPTER E. TEXAS WINDSTORM INSURANCE ASSOCIATION

DIVISION 10. ELIGIBILITY AND FORMS

28 TAC §5.4905

The commissioner of insurance adopts amendments to 28 TAC §5.4905, concerning minimum retained premium. The amendments are adopted with a nonsubstantive change to the proposed text published in the August 16, 2024, issue of the *Texas Register* (49 TexReg 6148). The adoption removes an extra "or" in subsection (b)(1). The section will be republished.

REASONED JUSTIFICATION. Amendments to §5.4905 are necessary to implement changes that House Bill 3208, 88th Legislature, 2023, made to Insurance Code §2210.204. HB 3208 limited the circumstances in which the Texas Windstorm Insurance Association (TWIA) must refund premium when an insured cancels an insurance policy.

Descriptions of the adopted amendments follow.

Section 5.4905. Amendments to subsection (a) clarify that the minimum retained premium provision is subject to Insurance Code §2210.204 and specify that--except as provided in the rule--the minimum retained premium on a TWIA policy is equal to the premium for the full annual policy term.

Existing subsection (b) is replaced by a new subsection (b). New subsection (b) still provides that a TWIA policy is subject to a $100 minimum retained premium if it is cancelled for specific reasons, but it now refers to the reasons specified in Insurance Code §2210.204(d). The new rule maintains as reasons current provisions that include a change in the majority ownership of the insured property, including foreclosure, and the death of the policyholder. The text of subsection (b) as proposed is changed to remove an extra use of the word "or."

A new subsection (c) is added that maintains the requirement from current subsection (b) that if any unearned premium remains after applying the minimum retained premium, then it must be refunded pro rata. Existing subsections (c) and (d) are redesignated as (d) and (e) to reflect the insertion of new subsection (c).

In addition, the proposed amendments include nonsubstantive changes to conform the section to the agency's current drafting style, plain language preferences, and to improve the rule's clarity. Examples include replacing "Association" with "TWIA" and the phrase "shall not" with "may not" and "shall be" with "is."

Amendments also delete obsolete language specifying the applicable minimum retained premium for policies effective before and after November 27, 2011. To clarify the section, existing text is restructured and language that is effectively duplicative is eliminated.

SUMMARY OF COMMENTS. TDI provided an opportunity for public comment on the rule proposal for a period that ended on September 16, 2024. TDI did not receive any comments on the amendments.

STATUTORY AUTHORITY. The commissioner adopts the amendments to 28 TAC §5.4905 under Insurance Code §2210.008(b) and §36.001.

Insurance Code §2210.008(b) provides that the commissioner may adopt rules that are reasonable and necessary to implement Insurance Code Chapter 2210.

Insurance Code §36.001 provides that the commissioner may adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

§5.4905 Minimum Retained Premium.

(a) Except as provided in this section and subject to Insurance Code §2210.204, concerning Cancellation of Certain Coverage, for cancellation of insurance coverage, the minimum retained premium on a TWIA policy issued on an annual basis is equal to the premium for the full annual policy term.

(b) A TWIA policy is subject to a $100 minimum retained premium if it is canceled because of:

(1) any of the reasons specified in Insurance Code §2210.204(d);

(2) a change in majority ownership of the insured property, including foreclosure of the insured property; or

(3) the death of the policyholder.

(c) Any unearned premium after the application of the minimum retained premium in this section must be refunded pro rata.

(d) TWIA may not issue a new or renewal policy to an applicant who owes premium on a prior TWIA policy.

(e) The minimum retained premium may not create or extend coverage beyond the policy's effective cancellation date.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 19, 2024.

TRD-202406136
Jessica Barta
General Counsel
Texas Department of Insurance
Effective date: January 8, 2025
Proposal publication date: August 16, 2024
For further information, please call: (512) 676-6555

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TITLE 30. ENVIRONMENTAL QUALITY

PART 1. TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

CHAPTER 290. PUBLIC DRINKING WATER

SUBCHAPTER D. RULES AND REGULATIONS FOR PUBLIC WATER SYSTEMS

30 TAC §§290.38, 290.45, 290.46

The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts amendments to §§290.38, 290.45 and 290.46.

Amended §290.45 is adopted without changes to the proposed text as published in the August 16, 2024, issue of the *Texas Register* (49 TexReg 6165) and, therefore, will not be republished. Amended §290.38 and §290.46 are adopted with changes, to the proposed text in response to comment and, therefore, will be republished.

Background and Summary of the Factual Basis for the Adopted Rules

During the 88th Texas Legislature (2023), House Bill (HB) 3810, HB 4559, and Senate Bill (SB) 594 passed and require amendments to 30 Texas Administrative Code (TAC) Chapter 290 to implement the enacted legislation.

This rulemaking reflects changes to Texas Health and Safety Code (THSC), §341.033 enacted in HB 3810, requiring nonindustrial water systems to report to the commission an unplanned condition that has caused the system to issue drinking water advisories or a boil water notice. The adopted rules provide a definition of "nonindustrial water system" and "unplanned condition" and address notification requirements.

This rulemaking reflects changes to Texas Water Code (TWC), §13.1395 enacted in HB 4559, which amended the definition of "affected utility" by changing county population. The amended population maintains the applicability of the counties required to have an Emergency Preparedness Plan (EPP) under TWC, §13.1395 or TWC, §13.1394.

This rulemaking reflects changes to THSC, §341.0315 enacted in SB 594, which requires the commission to establish equivalency values for each meter size used to serve a "recreational vehicle park", as defined by TWC, §13.087, to determine connection count. The adopted rules establish the equivalency value and establish how public water systems calculate alternatives to connection count for recreational vehicle parks that are metered customers of a public water system and have actual water usage more than 10% below the equivalency value.

Section by Section Discussion

§290.38, Definitions

The commission adopts the amendment to §290.38(3)(B) defining "affected utility," by changing the population from "550,000" to "800,000" in accordance with TWC, §13.1395 as amended by HB 4559. The amended population maintains the applicability of the counties required to have an EPP under TWC, §13.1395 or TWC, §13.1394. Specifically, the amendment maintains TWC, §13.1395 applicability to Fort Bend and Harris counties.

The commission adopts the amendment to §290.38(18), defining "connection," by adding a connection equivalency value as well as the alternative recreational vehicle park connection equivalency for recreational vehicle parks that are retail customers of public water systems. The adopted definition establishes that the number of connections for these recreational vehicle parks is calculated as the number of recreational vehicle or cabin sites divided by eight in accordance with THSC, §341.0315 as amended by SB 594.

The commission adopts the addition of §290.38(76), which defines "Recreational Vehicle" in response to public comment.

§290.45, Minimum Water System Capacity Requirements

The commission adopts new §290.45(j) to establish the process by which a public water system can calculate an alternative recreational vehicle park connection equivalency for recreational vehicle parks that are retail customers of a public water system, to coincide with the amended definition of "connection" in §290.38(18)(B) in accordance with THSC, §341.0315 as amended by SB 594. A table is provided with the Alternative Recreational Vehicle Park Connection Equivalency utilizing significant figures; the calculations are based on source capacity per connection in accordance with TAC §290.45(b) and (c) as well as the definition of maximum daily demand in §290.38.

§290.46, Minimum Acceptable Operating Practices for Public Water Systems

In accordance with THSC, §341.033 as amended by HB 3810, the commission adopts the amendment to §290.46(w) and adds new §290.46(w)(6) to require nonindustrial public water systems to provide the executive director with immediate notification of unplanned conditions resulting in water system outages that result in drinking water advisories or boil water notices and to define "nonindustrial water system" and "unplanned condition" within §290.46(w)(6) to clarify public water system types and situations, respectively.

Final Regulatory Impact Determination

The commission reviewed this rulemaking in light of the regulatory analysis requirements of Texas Government Code §2001.0225 and determined that the rulemaking is not subject to §2001.0225. A "Major environmental rule" means a rule with a specific intent to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

First, the rulemaking does not meet the statutory definition of a "Major environmental rule" because its specific intent is not to protect the environment or reduce risks to human health from environmental exposure. The specific intent of the rulemaking is to address unplanned conditions at a nonindustrial public water system that cause an outage or issuance of drinking water advisories or boil water notices; to revise the county population in the definition of affected utility in accordance with TWC, §13.1395(a)(1), which applies to those affected utilities which need to submit emergency preparedness plans to the commission for review and approval; and to meet the legislative requirement for the commission to establish connection equivalency values for each meter size used to serve recreational vehicle parks for use in determining the number of connections served by a public water system.

Second, the rulemaking does not meet the statutory definition of a "Major environmental rule" because the rules will not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. It is not anticipated that the cost of complying with the rules will be significant with respect to the economy as a whole or with respect to a sector of the economy; therefore, the amendments will not adversely affect in a material way the economy, a sector of the economy, competition, or jobs.

Finally, the rulemaking does not meet any of the four applicability requirements for a "Major environmental rule" listed in Texas Government Code §2001.0225(a). Section §2001.0225 only applies to a major environmental rule, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law. This rulemaking does not meet any of the preceding four applicability requirements because this rulemaking: does not exceed any standard set by federal law for public water systems; does not exceed any express requirement of state law; does not exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government; and is not based solely under the general powers of the agency, but under THSC, §341.031 and §341.0315, which allows the commission to adopt and enforce rules related to public drinking water, as well under the general powers of the commission.

The commission invited public comment regarding the Draft Regulatory Impact Analysis Determination during the public comment period. No comments were received regarding the regulatory impact analysis determination.

Takings Impact Assessment

The commission evaluated this rulemaking and performed a preliminary assessment of whether these rules constitute a taking under Texas Government Code, Chapter §2007.

The commission adopts these rules to implement House Bills 3810, 4559 and Senate Bill 594, 88th Texas Legislative Session (2023). HB 3810 amended THSC, §341.033 by requiring nonindustrial public water systems to notify the commission when an unplanned condition caused a public water supply outage or issuance of drinking water advisories or a boil water notice. HB 4559 amended TWC, §13.1394(a)(1) by changing the county population in the definition of "affected utility." An affected utility is required to file an emergency preparedness plan with the executive director for review and approval. SB 594 amended THSC, §341.0315, which requires the commission to adopt rules establishing connection equivalency values for each retail meter size used to serve a recreational vehicle park in calculating connection counts.

The commission's analysis indicates that Texas Government Code, Chapter §2007, does not apply to these rules based upon exceptions to applicability in Texas Government Code, §2007.003(b). The rulemaking is an action that is taken to fulfill obligations mandated under state law for all of the adopted rules. The rulemaking related to emergency preparedness plans is also an action taken in response to a real and substantial threat to public health and safety, that is designed to significantly advance the public health and safety purpose, and that does not impose a greater burden than is necessary to achieve the public health and safety purpose. Texas Government Code, §2007.003(b)(4) and (13).

First, the rulemaking is an action taken to fulfill obligations under state law. The law requires actions by the commission and the regulated community when unplanned conditions at a nonindustrial public water system result in a system outage or issuance of drinking water advisories or boil water notices under THSC, §341.033; the change to the county population in the definition of "affected utility" maintains those affected utilities requirements to submit emergency preparedness plans to the commission under TWC, §13.1395(a)(1); and state law now requires the commission to promulgate rules to establish connection equivalency values for each meter size used to serve a recreational vehicle park for purposes of public water system connection counts under THSC, §341.0315. Texas Government Code, §2007.003(b)(4).

Second, the adopted rules will ensure the emergency preparedness plans are submitted by affected utilities in appropriate counties designated by the legislature. The adopted rules will significantly advance the public health and safety purpose; and do not impose a greater burden than is necessary to achieve the public health and safety purpose. These rules advance the public health and safety by ensuring appropriate governmental regulation and do so in a way that does not impose a greater burden than is necessary to achieve the public health and safety purpose. Texas Government Code, §2007.003(b)(13).

Further, the commission has determined that promulgation and enforcement of these rules will be neither a statutory nor a constitutional taking of private real property. Specifically, there are no burdens imposed on private real property under the rule because the rules neither relate to, nor have any impact on, the use or enjoyment of private real property, and there will be no reduction in property value as a result of these rules. The rules require compliance with the actions required by nonindustrial public water systems when unplanned conditions result in a system outage or issuance of drinking water advisories or boil water notices; compliance regarding submission by an affected utility to the commission of its emergency preparedness plan, which is meant to ensure public health and safety; and state law requires that connection equivalency values be established for each retail meter size used to serve a recreational vehicle park. Therefore, the rules will not constitute a taking under Texas Government Code, Chapter §2007.

Consistency with the Coastal Management Program

The commission reviewed the adopted rulemaking and found that the sections proposed for amendments are neither identified in Coastal Coordination Act implementation rules, 31 TAC §505.11(b)(2) or (4), nor will the amendments affect any action or authorization identified in Coastal Coordination Act implementation rules, 31 TAC §505.11(a)(6). Therefore, the adopted rulemaking is not subject to the Texas Coastal Management Program.

The commission invited public comment regarding the consistency with the coastal management program during the public comment period. No comments were received regarding the Coastal Management Program.

Public Comment

The commission held a public hearing on Thursday, September 12, 2024. No oral comments were received at the public hearing. The comment period closed on Tuesday, September 17, 2024. The commission received timely comments on the proposed Chapter 290 rules from Texas Rural Water Association (TRWA).

Response to Comments

Comment 1

TRWA expressed appreciation for being a partner with the commission in the rulemaking process and offered changes to the proposed rule language. TRWA indicated that SB 594 and HB 3810 had been confusing for some public water systems and TRWA believed some of the language proposing to implement these bills was ambiguous.

Response 1

The commission acknowledges this comment.

Comment 2

TRWA commented that §290.45(j) did not define "cabin," as used in SB 594 and asked whether "cabin" includes "tiny homes." TRWA provided a suggested definition of "cabin". TRWA commented that the proposed rules also do not define "recreational vehicle (RV)" or "recreational vehicle park (RV Park)," TRWA suggested that the commission adopt the same definitions of RV and RV park as used by the Texas Public Utility Commission.

Response 2

The commission does not agree that §290.45(j) needs to include the definition for "recreational vehicle park" (RV Park) or "cabin" as suggested by TRWA because proposed §290.38(18)(B) references TWC §13.087(a)(3), which defines RV Park, therefore the proposed rules are consistent with statutory definitions. The commission agrees that defining "recreational vehicle" would provide regulatory clarity to the rule and has added a new definition, §290.38(76), based on TWC §13.087(a)(2). The commission does not believe that a definition of "cabin" is necessary because TCEQ rules referring to transient accommodation units do not include a comprehensive list of accommodation units nor do they define specific accommodation units, such as hotel rooms or campsites. Cabins should be considered as "similar accommodations" to the transient accommodation units listed in 30 TAC §290.45(c). If the regulated community continues to express confusion regarding cabins and tiny homes as described by TRWA, the commission can clarify the issue through regulatory guidance.

Comment 3

The TRWA commented that the proposed changes to §290.46(w)(6) appear broader than what is required by HB 3810. TRWA suggests the commission revise the proposed rule by adding definitions for "do-not-use advisory" and "do-not-consume advisory." TRWA suggests that the reference to §290.47(e) in the proposed rule be replaced with reference to §290.46(q) because §290.47(e) addresses only boil water notices while §290.46(q) addresses special precautions.

Response 3

The commission does not agree that proposed §290.46(w)(6) is broader than HB 3810, however, to improve clarity the commission is revising 290.46(w) to include "do-not-use advisory" and "do-not-consume advisory" to be consistent with the statute. The commission does not agree that the rule should reference §290.46(q) in place of §290.47(e), because the flow diagram referenced by §290.47(e) specifically addresses outages and boil water notices associated with a loss of pressure. Proposed §290.46(w)(6) provides nonindustrial public water systems a framework to determine when they need to submit immediate notification and adequately implements HB 3810.

Statutory Authority

The rulemaking is adopted under Texas Water Code (TWC) §5.013, which establishes the general jurisdiction of the commission; TWC §5.102, which establishes the commission's general authority to perform any act necessary to carry out its jurisdiction; TWC §5.103 and TWC §5.105, which establish the commission's authority to adopt any rules necessary to carry out its powers and duties; Texas Health and Safety Code (THSC) §341.031, which requires drinking water supplies to meet standards established by the commission; and THSC §341.0315, which requires public drinking water systems to comply with commission standards established to ensure the supply of safe drinking water.

The rulemaking adoption implements legislation enacted by the 88th Texas Legislature in 2023: THSC, §341.033 in House Bill (HB) 3810; TWC, §13.1395(a)(1) in HB 4559; and THSC, §341.0315 in Senate Bill 594.

§290.38. Definitions.

The following words and terms, when used in this chapter shall have the following meanings, unless the context clearly indicates otherwise. If a word or term used in this chapter is not contained in the following list, its definition shall be as shown in 40 Code of Federal Regulations (CFR) §141.2. Other technical terms used shall have the meanings or definitions listed in the latest edition of The Water Dictionary: A Comprehensive Reference of Water Terminology, prepared by the American Water Works Association.

(1) Accredited laboratory - A laboratory accredited by the executive director to analyze drinking water samples to determine compliance with maximum contaminant levels, action levels, and microbial contaminants in accordance with §290.119 of this title (relating to Analytical Procedures).

(2) Adverse Weather Conditions - Any significant temperature, wind velocity, accumulation of precipitation including drought, or other weather pattern that may trigger the issuance of a national weather service watch, advisory, or warning.

(3) Affected utility -

(A) A retail public utility (§291.3 of this title (relating to Definitions of Terms)), exempt utility (§291.103 of this title (relating to Certificates Not Required)), or provider or conveyor of potable or raw water service that furnishes water service to more than one customer is an affected utility as defined in TWC §13.1394; or

(B) A retail public utility (§291.3 of this title (relating to Definitions of Terms)), exempt utility (§291.103 of this title (relating to Certificates Not Required)), or provider or conveyor of potable or raw water service that furnishes water service to more than one customer is an affected utility, as defined in TWC §13.1395, in a county with a population of:

(i) 3.3 million or more; or

(ii) 800,000 or more adjacent to a county with a population of 3.3 million or more.

(4) Air gap--The unobstructed vertical distance through the free atmosphere between the lowest opening from any pipe or faucet conveying water to a tank, fixture, receptor, sink, or other assembly and the flood level rim of the receptacle. The vertical, physical separation must be at least twice the diameter of the water supply outlet, but never less than 1.0 inch.

(5) American National Standards Institute (ANSI) standards--The standards of the American National Standards Institute, Inc.

(6) American Society of Mechanical Engineers (ASME) standards--The standards of the ASME.

(7) American Water Works Association (AWWA) standards--The latest edition of the applicable standards as approved and published by the AWWA.

(8) Approved laboratory--A laboratory approved by the executive director to analyze water samples to determine their compliance with treatment technique requirements and maximum or minimum allowable constituent levels in accordance with §290.119 of this title (relating to Analytical Procedures).

(9) ASTM International standards--The standards of ASTM International (formerly known as the American Society for Testing and Materials).

(10) Auxiliary power--Either mechanical power or electric generators which can enable the system to provide water under pressure to the distribution system in the event of a local power failure. With the approval of the executive director, dual primary electric service may be considered as auxiliary power in areas which are not subject to large scale power outages due to natural disasters.

(11) Bag filter--Pressure-driven separation device that removes particulate matter larger than 1 micrometer using an engineered porous filtration media. They are typically constructed of a non-rigid, fabric filtration media housed in a pressure vessel in which the direction of flow is from the inside of the bag to the outside.

(12) Baseline performance--In reference to a membrane treatment facility, the detailed assessment of observed operational conditions at the time the membrane facility is placed in service for the purpose of tracking changes over time and determining when maintenance or service is required. Examples of parameters where baseline performance data is collected include: net driving pressure, normalized permeate flow, salt rejection, and salt passage.

(13) Cartridge filter--Pressure-driven separation device that removes particulate matter larger than 1 micrometer using an engineered porous filtration media. They are typically constructed as rigid or semi-rigid, self-supporting filter elements housed in pressure vessels in which flow is from the outside of the cartridge to the inside.

(14) Certified laboratory--A laboratory certified by the commission to analyze water samples to determine their compliance with maximum allowable constituent levels. After June 30, 2008, laboratories must be accredited, not certified, in order to perform sample analyses previously performed by certified laboratories.

(15) Challenge test--A study conducted to determine the removal efficiency (log removal value) of a device for a particular organism, particulate, or surrogate.

(16) Chemical disinfectant--Any oxidant, including but not limited to chlorine, chlorine dioxide, chloramines, and ozone added to the water in any part of the treatment or distribution process, that is intended to kill or inactivate pathogenic microorganisms.

(17) Community water system--A public water system which has a potential to serve at least 15 residential service connections on a year-round basis or serves at least 25 residents on a year-round basis.

(18) Connection--A single family residential unit or each commercial or industrial establishment to which drinking water is supplied from the system. As an example, the number of service connections in an apartment complex would be equal to the number of individual apartment units. When enough data is not available to accurately determine the number of connections to be served or being served, the population served divided by three will be used as the number of connections for calculating system capacity requirements. Conversely, if only the number of connections is known, the connection total multiplied by three will be the number used for population served. For the purposes of this definition:

(A) a dwelling or business which is connected to a system that delivers water by a constructed conveyance other than a pipe shall not be considered a connection if:

(i) the water is used exclusively for purposes other than those defined as human consumption (see human consumption);

(ii) the executive director determines that alternative water to achieve the equivalent level of public health protection provided by the drinking water standards is provided for residential or similar human consumption, including, but not limited to, drinking and cooking; or

(iii) the executive director determines that the water provided for residential or similar human consumption is centrally treated or is treated at the point of entry by a provider, a pass through entity, or the user to achieve the equivalent level of protection provided by the drinking water standards.

(B) For a recreational vehicle park, as defined by Texas Water Code, §13.087(a)(3), that is a retail customer of a public water system, the number of connections shall be calculated as:

(i) the number of recreational vehicle sites or cabin sites, whether occupied or not, divided by eight; or

(ii) the number of recreational vehicle sites or cabin sites, whether occupied or not, divided by the alternative recreational vehicle park connection equivalency specified in §290.45(j) of this title (relating to Minimum Water System Capacity Requirements).

(19) Contamination--The presence of any foreign substance (organic, inorganic, radiological, or biological) in water which tends to degrade its quality so as to constitute a health hazard or impair the usefulness of the water.

(20) Cross-connection--A physical connection between a public water system and either another supply of unknown or questionable quality, any source which may contain contaminating or polluting substances, or any source of water treated to a lesser degree in the treatment process.

(21) Direct integrity test--A physical test applied to a membrane unit in order to identify and isolate integrity breaches/leaks that could result in contamination of the filtrate.

(22) Disinfectant--A chemical or a treatment which is intended to kill or inactivate pathogenic microorganisms in water.

(23) Disinfection--A process which inactivates pathogenic organisms in the water by chemical oxidants or equivalent agents.

(24) Distribution system--A system of pipes that conveys potable water from a treatment plant to the consumers. The term includes pump stations, ground and elevated storage tanks, potable water mains, and potable water service lines and all associated valves, fittings, and meters, but excludes potable water customer service lines.

(25) Drinking water--All water distributed by any agency or individual, public or private, for the purpose of human consumption or which may be used in the preparation of foods or beverages or for the cleaning of any utensil or article used in the course of preparation or consumption of food or beverages for human beings. The term "drinking water" shall also include all water supplied for human consumption or used by any institution catering to the public.

(26) Drinking water standards--The commission rules covering drinking water standards in Subchapter F of this chapter (relating to Drinking Water Standards Governing Drinking Water Quality and Reporting Requirements for Public Water Systems).

(27) Elevated storage capacity--That portion of water which can be stored at least 80 feet above the highest service connection in the pressure plane served by the storage tank.

(28) Emergency operations--The operation of an affected utility during an extended power outage at a minimum water pressure of 20 pounds per square inch (psi) or a pressure approved by the executive director as required under TWC §13.1394 and 35 psi as required under TWC §13.1395.

(29) Emergency power--Either mechanical power or electric generators which can enable the system to provide water under pressure to the distribution system in the event of a local power failure. With the approval of the executive director, dual primary electric service may be considered as emergency power in areas which are not subject to large scale power outages due to natural disasters.

(30) Extended power outage--A power outage lasting for more than 24 hours.

(31) Filtrate--The water produced from a filtration process; typically used to describe the water produced by filter processes such as membranes.

(32) Flux--The throughput of a pressure-driven membrane filtration system expressed as flow per unit of membrane area. For example, gallons per square foot per day or liters per hour per square meter.

(33) Grantee--For purposes of this chapter, any person receiving an ownership interest in a public water system, whether by sale, transfer, descent, probate, or otherwise.

(34) Grantor--For purposes of this chapter, any person who conveys an ownership interest in a public water system, whether by sale, transfer, descent, probate, or otherwise.

(35) Groundwater--Any water that is located beneath the surface of the ground and is not under the direct influence of surface water.

(36) Groundwater under the direct influence of surface water--Any water beneath the surface of the ground with:

(A) significant occurrence of insects or other macroorganisms, algae, or large-diameter pathogens such as *Giardia lamblia* or *Cryptosporidium*;

(B) significant and relatively rapid shifts in water characteristics such as turbidity, temperature, conductivity, or pH which closely correlate to climatological or surface water conditions; or

(C) site-specific characteristics including measurements of water quality parameters, well construction details, existing geological attributes, and other features that are similar to groundwater sources that have been identified by the executive director as being under the direct influence of surface water.

(37) Health hazard--A cross-connection, potential contamination hazard, or other situation involving any substance that can cause death, illness, spread of disease, or has a high probability of causing such effects if introduced into the potable drinking water supply.

(38) Human consumption--Uses by humans in which water can be ingested into or absorbed by the human body. Examples of these uses include, but are not limited to drinking, cooking, brushing teeth, bathing, washing hands, washing dishes, and preparing foods.

(39) Indirect integrity monitoring--The monitoring of some aspect of filtrate water quality, such as turbidity, that is indicative of the removal of particulate matter.

(40) Innovative/alternate treatment--Any treatment process that does not have specific design requirements in §290.42(a) - (f) of this title (relating to Water Treatment).

(41) Interconnection--A physical connection between two public water supply systems.

(42) International Fire Code (IFC)--The standards of the International Code Council.

(43) Intruder-resistant fence--A fence six feet or greater in height, constructed of wood, concrete, masonry, or metal with three strands of barbed wire extending outward from the top of the fence at a 45 degree angle with the smooth side of the fence on the outside wall. In lieu of the barbed wire, the fence must be eight feet in height. The fence must be in good repair and close enough to surface grade to prevent intruder passage.

(44) L/d ratio--The dimensionless value that is obtained by dividing the length (depth) of a granular media filter bed by the weighted effective diameter "d" of the filter media. The weighted effective diameter of the media is calculated based on the percentage of the total bed depth contributed by each media layer.

(45) Licensed professional engineer--An engineer who maintains a current license through the Texas Board of Professional Engineers in accordance with its requirements for professional practice.

(46) Log removal value (LRV)--Removal efficiency for a target organism, particulate, or surrogate expressed as log10 (i.e., log10 (feed concentration) - log10 (filtrate concentration)).

(47) Maximum contaminant level (MCL)--The MCL for a specific contaminant is defined in the section relating to that contaminant.

(48) Maximum daily demand--In the absence of verified historical data or in cases where a public water system has imposed mandatory water use restrictions within the past 36 months, maximum daily demand means 2.4 times the average daily demand of the system.

(49) Membrane filtration--A pressure or vacuum driven separation process in which particulate matter larger than one micrometer is rejected by an engineered barrier, primarily through a size-exclusion mechanism, and which has a measurable removal efficiency of a target organism that can be verified through the application of a direct integrity test; includes the following common membrane classifications microfiltration (MF), ultrafiltration (UF), nanofiltration (NF), and reverse osmosis (RO), as well as any "membrane cartridge filtration" (MCF) device that satisfies this definition.

(50) Membrane LRVC-Test --The number that reflects the removal efficiency of the membrane filtration process demonstrated during challenge testing. The value is based on the entire set of log removal values (LRVs) obtained during challenge testing, with one representative LRV established per module tested.

(51) Membrane module--The smallest component of a membrane unit in which a specific membrane surface area is housed in a device with a filtrate outlet structure.

(52) Membrane sensitivity--The maximum log removal value that can be reliably verified by a direct integrity test.

(53) Membrane unit--A group of membrane modules that share common valving, which allows the unit to be isolated from the rest of the system for the purpose of integrity testing or other maintenance.

(54) Milligrams per liter (mg/L)--A measure of concentration, equivalent to and replacing parts per million in the case of dilute solutions.

(55) Monthly reports of water works operations--The daily record of data relating to the operation of the system facilities compiled in a monthly report.

(56) National Fire Protection Association (NFPA) standards--The standards of the NFPA.

(57) NSF International--The organization and the standards, certifications, and listings developed by NSF International (formerly known as the National Sanitation Foundation) related to drinking water.

(58) Noncommunity water system--Any public water system which is not a community system.

(59) Nonhealth hazard--A cross-connection, potential contamination hazard, or other situation involving any substance that generally will not be a health hazard, but will constitute a nuisance, or be aesthetically objectionable, if introduced into the public water supply.

(60) Nontransient, noncommunity water system--A public water system that is not a community water system and regularly serves at least 25 of the same persons at least six months out of the year.

(61) Pass--In reference to a reverse osmosis or nanofiltration membrane system, stages of pressure vessels in series in which the permeate from one stage is further processed in a following stage.

(62) Peak hourly demand--In the absence of verified historical data, peak hourly demand means 1.25 times the maximum daily demand (prorated to an hourly rate) if a public water supply meets the

commission's minimum requirements for elevated storage capacity and 1.85 times the maximum daily demand (prorated to an hourly rate) if the system uses pressure tanks or fails to meet the commission's minimum elevated storage capacity requirement.

(63) Plumbing inspector--Any person employed by a political subdivision for the purpose of inspecting plumbing work and installations in connection with health and safety laws and ordinances, who has no financial or advisory interest in any plumbing company, and who has successfully fulfilled the examinations and requirements of the Texas State Board of Plumbing Examiners.

(64) Plumbing ordinance--A set of rules governing plumbing practices which is at least as stringent and comprehensive as one of the following nationally recognized codes:

(A) the International Plumbing Code; or

(B) the Uniform Plumbing Code.

(65) Potable water customer service line--The sections of potable water pipe between the customer's meter and the customer's point of use.

(66) Potable water main--A pipe or enclosed constructed conveyance operated by a public water system which is used for the transmission or distribution of drinking water to a potable water service line.

(67) Potable water service line--The section of pipe between the potable water main and the customer's side of the water meter. In cases where no customer water meter exists, it is the section of pipe that is under the ownership and control of the public water system.

(68) Potential contamination hazard--A condition which, by its location, piping or configuration, has a reasonable probability of being used incorrectly, through carelessness, ignorance, or negligence, to create or cause to be created a backflow condition by which contamination can be introduced into the water supply. Examples of potential contamination hazards are:

(A) bypass arrangements;

(B) jumper connections;

(C) removable sections or spools; and

(D) swivel or changeover assemblies.

(69) Process control duties--Activities that directly affect the potability of public drinking water, including: making decisions regarding the day-to-day operations and maintenance of public water system production and distribution; maintaining system pressures; determining the adequacy of disinfection and disinfection procedures; taking routine microbiological samples; taking chlorine residuals and microbiological samples after repairs or installation of lines or appurtenances; and operating chemical feed systems, filtration, disinfection, or pressure maintenance equipment; or performing other duties approved by the executive director.

(70) psi--Pounds per square inch.

(71) Public drinking water program--Agency staff designated by the executive director to administer the Safe Drinking Water Act and state statutes related to the regulation of public drinking water. Any report required to be submitted in this chapter to the executive director must be submitted to the Texas Commission on Environmental Quality, Water Supply Division, MC 155, P.O. Box 13087, Austin, Texas 78711-3087.

(72) Public health engineering practices--Requirements in this chapter or guidelines promulgated by the executive director.

(73) Public water system--A system for the provision to the public of water for human consumption through pipes or other constructed conveyances, which includes all uses described under the definition for drinking water. Such a system must have at least 15 service connections or serve at least 25 individuals at least 60 days out of the year. This term includes: any collection, treatment, storage, and distribution facilities under the control of the operator of such system and used primarily in connection with such system, and any collection or pretreatment storage facilities not under such control which are used primarily in connection with such system. Two or more systems with each having a potential to serve less than 15 connections or less than 25 individuals but owned by the same person, firm, or corporation and located on adjacent land will be considered a public water system when the total potential service connections in the combined systems are 15 or greater or if the total number of individuals served by the combined systems total 25 or greater at least 60 days out of the year. Without excluding other meanings of the terms "individual" or "served," an individual shall be deemed to be served by a water system if he lives in, uses as his place of employment, or works in a place to which drinking water is supplied from the system.

(74) Quality Control Release Value (QCRV)--A minimum quality standard of a non-destructive performance test established by the manufacturer for membrane module production that ensures that the module will attain the targeted log removal value demonstrated during challenge testing.

(75) Reactor Validation Testing--A process by which a full-scale ultraviolet (UV) reactor's disinfection performance is determined relative to operating parameters that can be monitored. These parameters include flow rate, UV intensity as measured by a UV sensor and the UV lamp status.

(76) Recreational Vehicle--A recreational vehicle as defined in Tex. Water Code §13.087(a)(2), which is incorporated by reference as if fully set forth.

(77) Resolution--The size of the smallest integrity breach that contributes to a response from a direct integrity test in membranes used to treat surface water or groundwater under the direct influence of surface water.

(78) Sanitary control easement--A legally binding document securing all land, within 150 feet of a public water supply well location, from pollution hazards. This document must fully describe the location of the well and surrounding lands and must be filed in the county records to be legally binding. For an example, see commission Form 20698.

(79) Sanitary survey--An onsite review of a public water system's adequacy for producing and distributing safe drinking water by evaluating the following elements: water source; treatment; distribution system; finished water storage; pump, pump facilities, and controls; monitoring, reporting, and data verification; system management, operation and maintenance; and operator compliance.

(80) Service line--A pipe connecting the utility service provider's main and the water meter, or for wastewater, connecting the main and the point at which the customer's service line is connected, generally at the customer's property line.

(81) Service pump--Any pump that takes treated water from storage and discharges to the distribution system.

(82) Significant deficiency--Significant deficiencies cause, or have the potential to cause, the introduction of contamination into

water delivered to customers. This may include defects in design, operation, or maintenance of the source, treatment, storage, or distribution systems.

(83) Stage--In reference to a reverse osmosis or nanofiltration membrane system, a set of pressure vessels installed in parallel.

(84) System--Public water system as defined in this section unless otherwise modified (i.e., distribution system).

(85) Transfer pump--Any pump which conveys water from one point to another within the treatment process or which conveys water to storage facilities prior to distribution.

(86) Transient, noncommunity water system--A public water system that is not a community water system and serves at least 25 persons at least 60 days out of the year, yet by its characteristics, does not meet the definition of a nontransient, noncommunity water system.

(87) Vessel--In reference to a reverse osmosis or nanofiltration membrane system, a cylindrical housing unit where membrane modules are placed in a series to form one unit.

(88) Wastewater lateral--Any pipe or constructed conveyance carrying wastewater, running laterally down a street, alley, or easement, and receiving flow only from the abutting properties.

(89) Wastewater main--Any pipe or constructed conveyance which receives flow from one or more wastewater laterals.

(90) Water system--Public water system as defined in this section unless otherwise modified (i.e., distribution system).

§290.46. Minimum Acceptable Operating Practices for Public Drinking Water Systems.

(a) General. When a public drinking water supply system is to be established, plans shall be submitted to the executive director for review and approval prior to the construction of the system. All public water systems are to be constructed in conformance with the requirements of this subchapter and maintained and operated in accordance with the following minimum acceptable operating practices. Owners and operators shall allow entry to members of the commission and employees and agents of the commission onto any public or private property at any reasonable time for the purpose of inspecting and investigating conditions relating to public water systems in the state including the required elements of a sanitary survey as defined in §290.38 of this title (relating to Definitions). Members, employees, or agents acting under this authority shall observe the establishment's rules and regulations concerning safety, internal security, and fire protection, and if the property has management in residence, shall notify management or the person then in charge of his presence and shall exhibit proper credentials.

(b) Microbiological. Submission of samples for microbiological analysis shall be as required by Subchapter F of this chapter (relating to Drinking Water Standards Governing Drinking Water Quality and Reporting Requirements for Public Water Systems). Microbiological samples may be required by the executive director for monitoring purposes in addition to the routine samples required by the drinking water standards. These samples shall be submitted to an accredited laboratory. (A list of the accredited laboratories can be obtained by contacting the executive director.) The samples shall be submitted to the executive director in a manner prescribed by the executive director.

(c) Chemical. Samples for chemical analysis shall be submitted as directed by the executive director.

(d) Disinfectant residuals and monitoring. A disinfectant residual must be continuously maintained during the treatment process and throughout the distribution system.

(1) Disinfection equipment shall be operated and monitored in a manner that will assure compliance with the requirements of §290.110 of this title (relating to Disinfectant Residuals).

(2) The disinfection equipment shall be operated to maintain the following minimum disinfectant residuals in each finished water storage tank and throughout the distribution system at all times:

(A) a free chlorine residual of 0.2 milligrams per liter (mg/L); or

(B) a chloramine residual of 0.5 mg/L (measured as total chlorine) for those systems that distribute chloraminated water.

(e) Operation by trained and licensed personnel. Except as provided in paragraph (1) of this subsection, the production, treatment, and distribution facilities at the public water system must be operated at all times under the direct supervision of a water works operator who holds an applicable, valid license issued by the executive director. Except as provided in paragraph (1) of this subsection, all public water systems must use a water works operator who holds an applicable, valid license issued by the executive director to meet the requirements of this subsection. The licensed operator of a public water system may be an employee, contractor, or volunteer.

(1) Transient, noncommunity public water systems are exempt from the requirements of this subsection if they use only groundwater or purchase treated water from another public water system.

(2) All public water systems that are subject to the provisions of this subsection shall meet the following requirements.

(A) Public water systems shall not allow new or repaired production, treatment, storage, pressure maintenance, or distribution facilities to be placed into service without the prior guidance and approval of a licensed water works operator.

(B) Public water systems shall ensure that their operators are trained regarding the use of all chemicals used in the water treatment plant. Training programs shall meet applicable standards established by the Occupational Safety and Health Administration or the Texas Hazard Communication Act, Texas Health and Safety Code, Chapter 502.

(C) Public water systems using chlorine dioxide shall place the operation of the chlorine dioxide facilities under the direct supervision of a licensed operator who has a Class "C" or higher license.

(D) Effective September 1, 2016, reverse osmosis or nanofiltration membrane systems must have operators that have successfully completed at least one executive director-approved training course or event specific to the operations and maintenance of reverse osmosis or nanofiltration membrane treatment.

(3) Systems that only purchase treated water shall meet the following requirements in addition to the requirements contained in paragraph (2) of this subsection.

(A) Purchased water systems serving no more than 250 connections must use an operator who holds a Class "D" or higher license.

(B) Purchased water systems serving more than 250 connections, but no more than 1,000 connections, must use an operator who holds a Class "C" or higher license.

(C) Purchased water systems serving more than 1,000 connections must use at least two operators who hold a Class "C" or higher license and who each work at least 16 hours per month at the public water system's treatment or distribution facilities.

(4) Systems that treat groundwater and do not treat surface water or groundwater that is under the direct influence of surface water shall meet the following requirements in addition to the requirements contained in paragraph (2) of this subsection.

(A) Groundwater systems serving no more than 250 connections must use an operator with a Class "D" or higher license.

(B) Groundwater systems serving more than 250 connections, but no more than 1,000 connections, must use an operator with a Class "C" or higher groundwater license.

(C) Groundwater systems serving more than 1,000 connections must use at least two operators who hold a Class "C" or higher groundwater license and who each work at least 16 hours per month at the public water system's production, treatment, or distribution facilities.

(5) Systems that treat groundwater that is under the direct influence of surface water must meet the following requirements in addition to the requirements contained in paragraph (2) of this subsection.

(A) Systems which serve no more than 1,000 connections and utilize cartridge or membrane filters must use an operator who holds a Class "C" or higher groundwater license and has completed a four-hour training course on monitoring and reporting requirements or who holds a Class "C" or higher surface water license and has completed the Groundwater Production course.

(B) Systems which serve more than 1,000 connections and utilize cartridge or membrane filters must use at least two operators who meet the requirements of subparagraph (A) of this paragraph and who each work at least 24 hours per month at the public water system's production, treatment, or distribution facilities.

(C) Systems which serve no more than 1,000 connections and utilize coagulant addition and direct filtration must use an operator who holds a Class "C" or higher surface water license and has completed the Groundwater Production course or who holds a Class "C" or higher groundwater license and has completed a Surface Water Production course. Effective January 1, 2007, the public water system must use at least one operator who has completed the Surface Water Production I course and the Surface Water Production II course.

(D) Systems which serve more than 1,000 connections and utilize coagulant addition and direct filtration must use at least two operators who meet the requirements of subparagraph (C) of this paragraph and who each work at least 24 hours per month at the public water system's production, treatment, or distribution facilities. Effective January 1, 2007, the public water system must use at least two operators who have completed the Surface Water Production I course and the Surface Water Production II course.

(E) Systems which utilize complete surface water treatment must comply with the requirements of paragraph (6) of this subsection.

(F) Each plant must have at least one Class "C" or higher operator on duty at the plant when it is in operation or the plant must be provided with continuous turbidity and disinfectant residual monitors with automatic plant shutdown and alarms to summon operators so as to ensure that the water produced continues to meet the commission's drinking water standards during periods when the plant is not staffed.

(6) Systems that treat surface water must meet the following requirements in addition to the requirements contained in paragraph (2) of this subsection.

(A) Surface water systems that serve no more than 1,000 connections must use at least one operator who holds a Class "B" or higher surface water license. Part-time operators may be used to meet the requirements of this subparagraph if the operator is completely familiar with the design and operation of the plant and spends at least four consecutive hours at the plant at least once every 14 days and the system also uses an operator who holds a Class "C" or higher surface water license. Effective January 1, 2007, the public water system must use at least one operator who has completed the Surface Water Production I course and the Surface Water Production II course.

(B) Surface water systems that serve more than 1,000 connections must use at least two operators; one of the required operators must hold a Class "B" or higher surface water license and the other required operator must hold a Class "C" or higher surface water license. Each of the required operators must work at least 32 hours per month at the public water system's production, treatment, or distribution facilities. Effective January 1, 2007, the public water system must use at least two operators who have completed the Surface Water Production I course and the Surface Water Production II course.

(C) Each surface water treatment plant must have at least one Class "C" or higher surface water operator on duty at the plant when it is in operation or the plant must be provided with continuous turbidity and disinfectant residual monitors with automatic plant shutdown and alarms to summon operators so as to ensure that the water produced continues to meet the commission's drinking water standards during periods when the plant is not staffed.

(D) Public water systems shall not allow Class "D" operators to adjust or modify the treatment processes at surface water treatment plant unless an operator who holds a Class "C" or higher surface license is present at the plant and has issued specific instructions regarding the proposed adjustment.

(f) Operating records and reports. All public water systems must maintain a record of water works operation and maintenance activities and submit periodic operating reports.

(1) The public water system's operating records must be organized, and copies must be kept on file or stored electronically.

(2) The public water system's operating records must be accessible for review during inspections and be available to the executive director upon request.

(3) All public water systems shall maintain a record of operations.

(A) The following records shall be retained for at least two years:

(i) the amount of chemicals used:

(I) Systems that treat surface water or groundwater under the direct influence of surface water shall maintain a record of the amount of each chemical used each day.

(II) Systems that serve 250 or more connections or serve 750 or more people shall maintain a record of the amount of each chemical used each day.

(III) Systems that serve fewer than 250 connections, serve fewer than 750 people, and use only groundwater or purchased treated water shall maintain a record of the amount of each chemical used each week;

(ii) the volume of water treated and distributed:

(I) Systems that treat surface water or groundwater under the direct influence of surface water shall maintain a record of the amount of water treated and distributed each day.

(II) Systems that serve 250 or more connections or serve 750 or more people shall maintain a record of the amount of water distributed each day.

(III) Systems that serve fewer than 250 connections, serve fewer than 750 people, and use only groundwater or purchase treated water shall maintain a record of the amount of water distributed each week.

(IV) Systems that serve 250 or more connections or serve 750 or more people and also add chemicals or provide pathogen or chemical removal shall maintain a record of the amount of water treated each day.

(V) Systems that serve fewer than 250 connections, serve fewer than 750 people, use only groundwater or purchase treated water, and also add chemicals or provide pathogen or chemical removal shall maintain a record of the amount of water treated each week;

(iii) the date, location, and nature of water quality, pressure, or outage complaints received by the system and the results of any subsequent complaint investigation;

(iv) the dates that dead-end mains were flushed;

(v) the dates that storage tanks and other facilities were cleaned;

(vi) the maintenance records for water system equipment and facilities. For systems using reverse osmosis or nanofiltration, maintain records of each clean-in-place process including the date, duration, and procedure used for each event;

(vii) for systems that do not employ full-time operators to meet the requirements of subsection (e) of this section, a daily record or a monthly summary of the work performed and the number of hours worked by each of the part-time operators used to meet the requirements of subsection (e) of this section; and

(viii) the owner or manager of a public water system that is operated by a volunteer to meet the requirements of subsection (e) of this section, shall maintain a record of each volunteer operator indicating the name of the volunteer, contact information for the volunteer, and the time period for which the volunteer is responsible for operating the public water system. These requirements apply to full-time and part-time licensed volunteer operators. Part-time licensed volunteer operators are excluded from the requirements of clause (vii) of this subparagraph.

(B) The following records shall be retained for at least three years:

(i) copies of notices of violation and any resulting corrective actions. The records of the actions taken to correct violations of primary drinking water regulations must be retained for at least three years after the last action taken with respect to the particular violation involved;

(ii) copies of any public notice issued by the water system;

(iii) the disinfectant residual monitoring results from the distribution system;

(iv) the calibration records for laboratory equipment, flow meters, rate-of-flow controllers, on-line turbidimeters, and on-line disinfectant residual analyzers;

(v) the records of backflow prevention device programs;

(vi) the raw surface water monitoring results and source water monitoring plans required by §290.111 of this title (relating to Surface Water Treatment) must be retained for three years after bin classification required by §290.111 of this title;

(vii) notification to the executive director that a system will provide 5.5-log *Cryptosporidium* treatment in lieu of raw surface water monitoring;

(viii) except for those specified in subparagraphs (C)(iv) and (E)(i) of this paragraph, the results of all surface water treatment monitoring that are used to demonstrate log inactivation or removal;

(ix) free and total chlorine, monochloramine, ammonia, nitrite, and nitrate monitoring results if chloramines are used in the water system; and

(x) the records of treatment effectiveness monitoring for systems using reverse osmosis or nanofiltration membranes. Treatment effectiveness monitoring includes the parameters for determining when maintenance is required. Examples of parameters to be monitored include conductivity (or total dissolved solids) on each membrane unit, pressure differential across a membrane vessel, flow, flux, and water temperature. At a minimum, systems using reverse osmosis or nanofiltration membranes must monitor the conductivity (or total dissolved solids) of the feed and permeate water once per day.

(C) The following records shall be retained for a period of five years after they are no longer in effect:

(i) the records concerning a variance or exemption granted to the system;

(ii) Concentration Time (CT) studies for surface water treatment plants;

(iii) the Recycling Practices Report form and other records pertaining to site-specific recycle practices for treatment plants that recycle; and

(iv) the turbidity monitoring results and exception reports for individual filters as required by §290.111 of this title.

(D) The following records shall be retained for at least five years:

(i) the results of microbiological analyses;

(ii) the results of inspections (as required in subsection (m)(1) of this section) for all water storage and pressure maintenance facilities;

(iii) the results of inspections (as required by subsection (m)(2) of this section) for all pressure filters;

(iv) documentation of compliance with state approved corrective action plan and schedules required to be completed by groundwater systems that must take corrective actions;

(v) documentation of the reason for an invalidated fecal indicator source sample and documentation of a total coliform-positive sample collected at a location with conditions that could cause such positive samples in a distribution system;

(vi) notification to wholesale system(s) of a distribution coliform-positive sample for consecutive systems using groundwater;

(vii) Consumer Confidence Report compliance documentation;

(viii) records of the lowest daily residual disinfectant concentration and records of the date and duration of any failure to maintain the executive director-approved minimum specified disinfectant residual for a period of more than four hours for groundwater systems providing 4-log treatment;

(ix) records of executive director-specified compliance requirements for membrane filtration, records of parameters specified by the executive director for approved alternative treatment and records of the date and duration of any failure to meet the membrane operating, membrane integrity, or alternative treatment operating requirements for more than four hours for groundwater systems. Membrane filtration can only be used if it is approved by the executive director and if it can be properly validated;

(x) assessment forms, regardless of who conducts the assessment, and documentation of corrective actions completed or documentation of corrective actions required but not yet completed as a result of those assessments and any other available summary documentation of the sanitary defects and corrective actions taken in accordance with §290.109 of this title (relating to Microbial Contaminants) for executive director review;

(xi) seasonal public water systems shall maintain executive director-approved start-up procedures and certification documentation in accordance with §290.109 of this title for executive director review; and

(xii) records of any repeat sample taken that meets the criteria for an extension of the 24-hour period for collecting repeat samples under §290.109 of this title.

(E) The following records shall be retained for at least ten years:

(i) copies of Monthly Operating Reports and any supporting documentation including turbidity monitoring results of the combined filter effluent;

(ii) the results of chemical analyses;

(iii) any written reports, summaries, or communications relating to sanitary surveys of the system conducted by the system itself, by a private consultant, or by the executive director shall be kept for a period not less than ten years after completion of the survey involved;

(iv) copies of the Customer Service Inspection reports required by subsection (j) of this section;

(v) copy of any Initial Distribution System Evaluation (IDSE) plan, report, approval letters, and other compliance documentation required by §290.115 of this title (relating to Stage 2 Disinfection Byproducts (TTHM and HAA5));

(vi) state notification of any modifications to an IDSE report;

(vii) copy of any 40/30 certification required by §290.115 of this title;

(viii) documentation of corrective actions taken by groundwater systems in accordance with §290.116 of this title (relating to Groundwater Corrective Actions and Treatment Techniques);

(ix) any Sample Siting Plans required by §290.109(d)(6) of this title and monitoring plans required by §290.121(b) of this title (relating to Monitoring Plans); and

(x) records of the executive director-approved minimum specified disinfectant residual and executive director-approved membrane system integrity monitoring results for groundwater systems providing 4-log treatment, including wholesale, and consecutive systems, regulated under §290.116(c) of this title.

(F) A public water system shall maintain records relating to lead and copper requirements under §290.117 of this title (relating to Regulation of Lead and Copper) for no less than 12 years. Any system subject to the requirements of §290.117 of this title shall retain on its premises original records of all sampling data and analyses, reports, surveys, letters, evaluations, schedules, executive determinations, and any other information required by the executive director under §290.117 of this title. These records include, but are not limited to, the following items: tap water monitoring results including the location of each site and date of collection; certification of the volume and validity of first-draw-tap sample criteria via a copy of the laboratory analysis request form; where residents collected the sample; certification that the water system informed the resident of proper sampling procedures; the analytical results for lead and copper concentrations at each tap sample site; and designation of any substitute site not used in previous monitoring periods.

(G) A public water system shall maintain records relating to special studies and pilot projects, special monitoring, and other system-specific matters as directed by the executive director.

(4) Public water systems shall submit routine reports and any additional documentation that the executive director may require to determine compliance with the requirements of this chapter.

(A) The reports must be submitted to the Texas Commission on Environmental Quality, Water Supply Division, MC 155, P.O. Box 13087, Austin, Texas 78711-3087 by the tenth day of the month following the end of the reporting period.

(B) The reports must contain all the information required by the drinking water standards and the results of any special monitoring tests which have been required.

(C) The reports must be completed in ink, typed, or computer-printed and must be signed by the licensed water works operator.

(5) All public water systems that are affected utilities under TWC §13.1394 or §13.1395 must maintain the following records for as long as they are applicable to the system:

(A) An emergency preparedness plan approved by the executive director and a copy of the approval letter.

(B) All required operating, inspection, testing, and maintenance records for auxiliary power equipment, and associated components required to be maintained, or actions performed as prescribed in §290.46(m)(8) of this title.

(C) Copies of the manufacturer's specifications for all generators that are part of the approved emergency preparedness plan.

(g) Disinfection of new or repaired facilities. Disinfection by or under the direction of water system personnel must be performed when repairs are made to existing facilities and before new facilities are placed into service. Disinfection must be performed in accordance with American Water Works Association (AWWA) requirements and water samples must be submitted to an accredited laboratory. The sample results must indicate that the facility is free of microbiological contamination before it is placed into service. When it is necessary to return repaired mains to service as rapidly as possible, doses may be increased to 500 mg/L and the contact time reduced to 1/2 hour.

(h) Calcium hypochlorite. A supply of calcium hypochlorite disinfectant shall be kept on hand for use when making repairs, setting meters, and disinfecting new mains prior to placing them in service.

(i) Plumbing ordinance. Public water systems must adopt an adequate plumbing ordinance, regulations, or service agreement with provisions for proper enforcement to ensure that neither cross-connections nor other unacceptable plumbing practices are permitted (See §290.47(b) of this title (relating to Appendices)). Should sanitary control of the distribution system not reside with the purveyor, the entity retaining sanitary control shall be responsible for establishing and enforcing adequate regulations in this regard. The use of pipes and pipe fittings that contain more than 0.25% lead or solders and flux that contain more than 0.2% lead is prohibited for installation or repair of any public water supply and for installation or repair of any plumbing in a residential or nonresidential facility providing water for human consumption and connected to a public drinking water supply system. This requirement may be waived for lead joints that are necessary for repairs to cast iron pipe.

(j) Customer service inspections. A customer service inspection certificate shall be completed prior to providing continuous water service to new construction, on any existing service either when the water purveyor has reason to believe that cross-connections or other potential contaminant hazards exist, or after any material improvement, correction, or addition to the private water distribution facilities. Any customer service inspection certificate form which varies from the format found in commission Form 20699 must be approved by the executive director prior to being placed in use.

(1) Individuals with the following credentials shall be recognized as capable of conducting a customer service inspection certification.

(A) Plumbing Inspectors and Water Supply Protection Specialists licensed by the Texas State Board of Plumbing Examiners (TSBPE).

(B) Customer service inspectors who have completed a commission-approved course, passed an examination administered by the executive director, and hold current professional license as a customer service inspector.

(2) As potential contaminant hazards are discovered, they shall be promptly eliminated to prevent possible contamination of the water supplied by the public water system. The existence of a health hazard, as identified in §290.47(f) of this title, shall be considered sufficient grounds for immediate termination of water service. Service can be restored only when the health hazard no longer exists, or until the health hazard has been isolated from the public water system in accordance with §290.44(h) of this title (relating to Water Distribution).

(3) These customer service inspection requirements are not considered acceptable substitutes for and shall not apply to the sanitary control requirements stated in §290.102(a)(5) of this title (relating to General Applicability).

(4) A customer service inspection is an examination of the private water distribution facilities for the purpose of providing or denying water service. This inspection is limited to the identification and prevention of cross-connections, potential contaminant hazards, and illegal lead materials. The customer service inspector has no authority or obligation beyond the scope of the commission's regulations. A customer service inspection is not a plumbing inspection as defined and regulated by the TSBPE. A customer service inspector is not permitted to perform plumbing inspections. State statutes and TSBPE adopted rules require that TSBPE licensed plumbing inspectors perform plumbing inspections of all new plumbing and alterations or additions to existing plumbing within the municipal limits of all cities, towns, and villages which have passed an ordinance adopting one of the plumbing codes recognized by TSBPE. Such entities may stipulate that the customer service inspection be performed by the plumbing inspector as a part of the more comprehensive plumbing inspection. Where such entities permit customer service inspectors to perform customer service inspections, the customer service inspector shall report any violations immediately to the local entity's plumbing inspection department.

(k) Interconnection. No physical connection between the distribution system of a public drinking water supply and that of any other water supply shall be permitted unless the other water supply is of a safe, sanitary quality and the interconnection is approved by the executive director.

(l) Flushing of mains. All dead-end mains must be flushed at monthly intervals. Dead-end lines and other mains shall be flushed as needed if water quality complaints are received from water customers or if disinfectant residuals fall below acceptable levels as specified in §290.110 of this title.

(m) Maintenance and housekeeping. The maintenance and housekeeping practices used by a public water system shall ensure the good working condition and general appearance of the system's facilities and equipment. The grounds and facilities shall be maintained in a manner so as to minimize the possibility of the harboring of rodents, insects, and other disease vectors, and in such a way as to prevent other conditions that might cause the contamination of the water.

(1) Each of the system's ground, elevated, and pressure tanks shall be inspected annually by water system personnel or a contracted inspection service.

(A) Ground and elevated storage tank inspections must determine that the vents are in place and properly screened, the roof hatches closed and locked, flap valves and gasketing provide adequate protection against insects, rodents, and other vermin, the interior and exterior coating systems are continuing to provide adequate protection to all metal surfaces, and the tank remains in a watertight condition.

(B) Pressure tank inspections must determine that the pressure release device and pressure gauge are working properly, the air-water ratio is being maintained at the proper level, the exterior coating systems are continuing to provide adequate protection to all metal surfaces, and the tank remains in watertight condition. Pressure tanks provided with an inspection port must have the interior surface inspected every five years.

(C) All tanks shall be inspected annually to determine that instrumentation and controls are working properly.

(2) When pressure filters are used, a visual inspection of the filter media and internal filter surfaces shall be conducted annually to ensure that the filter media is in good condition and the coating materials continue to provide adequate protection to internal surfaces.

(3) When cartridge filters are used, filter cartridges shall be changed at the frequency required by the manufacturer, or more frequently if needed.

(4) All water treatment units, storage and pressure maintenance facilities, distribution system lines, and related appurtenances shall be maintained in a watertight condition and be free of excessive solids.

(5) Basins used for water clarification shall be maintained free of excessive solids to prevent possible carryover of sludge and the formation of tastes and odors.

(6) Pumps, motors, valves, and other mechanical devices shall be maintained in good working condition.

(7) Reverse osmosis or nanofiltration membrane systems shall be cleaned, or replaced, in accordance with the allowable operating conditions of the manufacturer and shall be based on one or more of the following: increased salt passage, increased or decreased pressure differential, and/or change in normalized permeate flow.

(8) Emergency generators must be appropriately tested and maintained monthly under at least 30% load based on the manufacturer's name plate kilowatt (kW) rating for at least 30 minutes, or as recommended by the manufacturer, to ensure functionality during emergency situations.

(A) Emergency generators operated at water systems serving 1,000 connections or greater must be maintained in accordance with Level 2 maintenance requirements contained in the current National Fire Protection Association (NFPA) 110 Standard and manufacturer's recommendation. In addition, the water system must maintain an inventory of operational maintenance items, lubricants, and coolants for critical generator components.

(B) Emergency generators operated at water systems serving fewer than 1,000 connections must be maintained according to clauses (i) - (x) of this subparagraph, supplemented with any additional requirements not listed below as prescribed in the manufacturer's specifications, or Level 2 maintenance requirements contained in NFPA 110 Standard. In addition, the public water system must maintain an inventory of operational maintenance items, lubricants, and coolants for critical generator components.

(i) Prior to monthly generator start-up, inspect and perform any needed maintenance on the generator fuel system.

(I) Document tank levels and inspect fuel tanks for fuel contamination and condensation in the portion of the tank occupied by air. If contamination is suspected, replace or polish the contaminated fuel before use.

(II) Inspect fuel lines and fittings for breaks and degradation. Replace fuel lines if needed.

(III) Inspect fuel filters and water separators for water accumulation, clogging and sediment buildup. Replace fuel filters and separators at the frequency recommended by the manufacturer, or as needed.

(IV) Inspect fuel transfer pumps, float switches and valves, where provided, between holding tanks and the generator to verify that they are operating properly.

(V) Where provided, inspect fuel tank grounding rods, cathodic and generator lightning protection for damage that may render the protection ineffective.

(ii) While the generator is operating under load, inspect the fuel pump to verify that it is operating properly.

(iii) Prior to monthly generator start up, inspect and perform any needed maintenance on the generator lubrication system.

(I) Inspect oil lines and oil reservoirs for adequate oil levels, leaks, breaks and degradation. Change oil at the frequency recommended by the manufacturer.

(II) Grease all bearing components and grease fittings at the frequency recommended by the manufacturer.

(iv) Prior to monthly generator start up, inspect and perform any needed maintenance on the generator coolant system.

(I) Inspect the block heater, coolant lines and coolant reservoirs for adequate coolant levels, leaks, breaks and degradation; replace as needed.

(II) Inspect coolant filters for clogging and sediment buildup. Replace coolant filters at the frequency recommended by the manufacturer, or as needed.

(III) Inspect the radiator, fan system, belts and air intake and filters for obstruction, cracks, breaks, and leaks; replace as needed.

(v) While the generator is operating under load, inspect the exhaust manifold and muffler to verify that they are not obstructed or leaking, are in good working condition and that fumes are directed away from enclosed areas.

(vi) Where a generator is located inside an enclosed structure, a carbon monoxide monitor equipped with automatic alarms and generator shutdowns must be present and operational.

(vii) Prior to monthly generator start up, inspect and perform any needed maintenance on the generator electrical system.

(I) Confirm that all batteries are mounted and properly secured. Inspect battery chargers, wiring and cables for damage, corrosion, connection continuity, and that all contacts are securely tightened onto battery terminals.

(II) Inspect each battery unit for adequate electrolyte levels, charge retention and appropriate discharge voltage.

(viii) While the generator is operating under load, inspect engine starters and alternators to verify that they are operating properly.

(ix) At least once per month, inspect Programmable Logic Controllers (PLC) and Uninterrupted Power Supplies (UPC), where applicable, to ensure that they are water-tight and not subject to floods, are properly ventilated, and that backup power supplies have adequate charge.

(x) At least once per month, inspect switch gears to ensure they are water-tight and in good, working condition.

(9) All critical components as described in the table in §290.47(c) associated to the source, treatment, storage, or other facilities necessary for the continued operations and distribution of water to customers must be protected from adverse weather conditions. Weatherization methods must be maintained in good condition and replaced as needed to ensure adequate protection.

(n) Engineering plans and maps. Plans, specifications, maps, and other pertinent information shall be maintained to facilitate the operation and maintenance of the system's facilities and equipment. The following records shall be maintained on file at the public water system and be available to the executive director upon request.

(1) Accurate and up-to-date detailed as-built plans or record drawings and specifications for each treatment plant, pump station, and storage tank shall be maintained at the public water system until the facility is decommissioned. As-built plans of individual projects may be used to fulfill this requirement if the plans are maintained in an organized manner.

(2) An accurate and up-to-date map of the distribution system shall be available so that valves and mains can be easily located during emergencies.

(3) Copies of well completion data as defined in §290.41(c)(3)(A) of this title (relating to Water Sources) shall be kept on file for as long as the well remains in service.

(o) Filter backwashing at surface water treatment plants. Filters must be backwashed when a loss of head differential of six to ten feet is experienced between the influent and effluent loss of head gauges or when the turbidity level at the effluent of the filter reaches 1.0 nephelometric turbidity unit (NTU).

(p) Data on public water system ownership and management. The agency shall be provided with information regarding public water system ownership and management.

(1) When a public water system changes ownership, a written notice of the transaction must be provided to the executive director. The grantee shall notify the executive director of the change in ownership within 30 days after the effective date of the change in ownership by providing the name of the grantor, the effective date of the change in ownership, the physical and mailing address and phone number of the grantee, the public water system's drinking water supply identification number, and any other information necessary to identify the transaction.

(2) On an annual basis, the owner of a public water system shall provide the executive director with a list of all the operators and operating companies that the public water system uses. The notice shall contain the name, contact information, work status, license number, and license class of each operator and the name and registration number of each operating company. Public water systems may report the list of operators and operating companies to the executive director by utilizing the Texas Commission on Environmental Quality (TCEQ) online "Operator Notice" form. If reporting cannot be accomplished utilizing the TCEQ online "Operator Notice" form, then a public water system may report the list of operators and operating companies on the written "Operator Notice" form to the executive director by mail, email or facsimile. (See §290.47(d) of this title).

(q) Special precautions, protective measures, and boil water notices. Special precautions, protective measures, and boil water notices shall be instituted by the public water system as specified in this subsection in the event of low distribution pressures (below 20 pounds per square inch (psi)), water outages, microbiological samples found to contain *Escherichia coli* (*E. coli*) (or other approved fecal indicator), failure to maintain adequate disinfectant residuals, elevated finished water turbidity levels, or other conditions which indicate that the potability of the drinking water supply has been compromised. Special precautions, protective measures, and boil water notices are corrective or protective actions which shall be instituted by the public water system to comply with the requirements of this subsection.

(1) A public water system shall issue a boil water notice, special precaution, or protective measure to customers throughout the distribution system or in the affected area(s) of the distribution system as soon as possible, but in no case later than 24 hours after the public water system has met any of the criteria described in subparagraph (A) and (B) of this paragraph.

(A) Situations requiring boil water notices:

(i) The flowchart found in §290.47(e) of this title shall be used to determine if a boil water notice shall be issued by the public water system to customers in the event of a loss of distribution system pressure.

(ii) A public water system shall issue a boil water notice to customers for a violation of the MCL for E. coli (or other approved fecal indicator) as described in §290.109(b)(1) of this title.

(iii) A public water system shall issue a boil water notice to customers if the combined filter effluent turbidity of the finished water, produced by a treatment plant that is treating surface water or groundwater under the direct influence of surface water, is above the turbidity level requirements as described in §290.122(a)(1)(B) of this title.

(iv) A public water system shall issue a boil water notice to customers if the public water system has failed to maintain adequate disinfectant residuals as described in subsection (d) of this section and as described in §290.110 of this title (relating to Disinfectant Residuals) for more than 24 hours.

(v) A public water system shall issue a boil water notice to customers if a waterborne disease outbreak occurs as defined in 40 Code for Federal Regulations §141.2.

(B) Situations requiring special precautions or protective measures may be determined by the public water system or at the discretion of the executive director, as described in paragraph (5) of this subsection.

(2) Boil water notices, special precautions, or protective measures shall be issued to customers by using one or more of the Tier 1 delivery methods as described in §290.122(a)(2) of this title (relating to Public Notification) and shall be issued using the applicable language and format specified by the executive director.

(3) A copy of boil water notice, special precaution, or protective measure issued shall be provided to the executive director electronically, within 24 hours or no later than the next business day after the issuance by the public water system, and a signed Certificate of Delivery shall be provided to the executive director within ten days after issuance by the public water system in accordance with §290.122(f) of this title.

(4) Boil water notices, special precautions, or protective measures shall be multilingual where appropriate, based upon local demographics.

(5) Special precautions, protective measures, and boil water notices may be required at the discretion of the executive director and shall be instituted by the public water system, upon written notification to the public water system, and shall remain in effect until the public water system meets the requirements of subparagraph (C) of this paragraph and paragraph (6) of this subsection.

(A) Circumstances warranting the exercise of such discretion may include:

(i) the public water system has failed to provide any of the required compliance information to the executive director as described in §290.111(h)(2) of this title (relating to Surface Water Treatment) and the failure results in the inability of the executive director to determine compliance as described in §290.111(i) of this title or the existence of a potential or actual health hazard, as described in §290.38 of this title (relating to Definitions); or

(ii) waterborne emergencies for situations that do not meet the definition of waterborne disease outbreak as defined in 40 Code of Federal Regulations §141.2, but that still have the potential to have serious adverse health effects as a result of short-term exposure. These can include, but are not limited to, outbreaks not related to treatment deficiencies, as well as situations that have the potential to cause outbreaks, such as failures or significant interruption in water treatment processes, natural disasters that disrupt the water supply or distribution system, chemical spills, or unexpected loading of possible pathogens into the source water.

(B) The executive director will provide written notification to the public water system in the event a public water system is required to institute special precautions, protective measures, or issue boil water notices to customers at the discretion of the executive director. Upon written notification from the executive director, the public water system shall implement special precautions, protective measures, or issue boil water notices to customers within 24 hours or within the time period specified by the executive director. The executive director may specify, in writing, additional required actions to the requirements described in paragraph (6) of this subsection for a public water system to rescind the notice.

(C) The public water system shall provide any required information to the executive director to document that the public water system has met the rescind requirements for special precautions, protective measures, and boil water notices required at the discretion of the executive director under this paragraph.

(6) Once the boil water notice, special precaution, or protective measure is no longer in effect, the public water system shall notify customers that the notice has been rescinded. A public water system shall not rescind a notice or notify customers that a notice has been rescinded until the public water system has met all the applicable requirements, as described in subparagraph (A) of this paragraph.

(A) Required actions prior to rescinding a boil water notice include:

(i) water distribution system pressures in excess of 20 psi are consistently being maintained throughout the distribution system in accordance with the flowchart found in §290.47(e) of this title (relating to Appendices);

(ii) a minimum of 0.2 mg/L free chlorine residual or 0.5 mg/L chloramine residual (measured as total chlorine) is present and is consistently being maintained in each finished water storage tank and throughout the distribution system as described in subsection (d) of this section;

(iii) finished water entering the distribution system, produced by a treatment plant that is treating surface water or groundwater under the direct influence of surface water, has a turbidity level that is consistently below 1.0 NTU and the affected areas of the distribution system have been thoroughly flushed;

(iv) additional actions may be required by the executive director, in writing, and these additional actions shall be completed and documentation provided to the executive director for approval prior to the public water system rescinding the notice, and

(v) water samples for microbiological analysis, marked as "special" on the laboratory sample submission form, were collected from representative locations throughout the distribution system or in the affected area(s) of the distribution system after the public water system has met all other applicable requirements of this paragraph and the water samples collected for microbiological analysis are found negative for coliform organisms. The water samples described in this subparagraph shall be analyzed at laboratories in accordance with §290.119 of this title (relating to Analytical Procedures).

(B) A public water system shall notify customers that the notice has been rescinded within 24 hours or no later than the next business day, using language and format specified by the executive director once the public water system has met the requirements of this paragraph. The method of delivery of the rescind notice must be in a manner similar to the original notice.

(C) The public water system shall provide a copy of the rescind notice, a copy of the associated microbiological laboratory analysis results, as required by subparagraph (A) of this paragraph, and a signed Certificate of Delivery to the executive director within ten days after the public water system has issued the rescind notice to customers in accordance with §290.122(f) of this title.

(r) Minimum pressures. All public water systems shall be operated to provide a minimum pressure of 35 psi throughout the distribution system under normal operating conditions. The system shall also be operated to maintain a minimum pressure of 20 psi during emergencies such as firefighting. As soon as safe and practicable following the occurrence of a natural disaster, a public water system that is an affected utility, as defined in TWC §13.1394 or §13.1395, shall maintain a minimum of 20 psi or a pressure approved by the executive director, or 35 psi, respectively, throughout the distribution system during an extended power outage.

(s) Testing equipment. Accurate testing equipment or some other means of monitoring the effectiveness of any chemical treatment or pathogen inactivation or removal processes must be used by the system.

(1) Flow-measuring devices and rate-of-flow controllers that are required by §290.42(b) and (d) of this title (relating to Water Treatment) shall be calibrated at least once every 12 months. Well meters required by §290.41(c)(3)(N) of this title shall be calibrated at least once every three years.

(2) Laboratory equipment used for compliance testing shall be properly calibrated.

(A) pH meters shall be properly calibrated.

(i) Benchtop pH meters shall be calibrated according to manufacturer specifications at least once each day.

(ii) The calibration of benchtop pH meters shall be checked with at least one buffer each time a series of samples is run, and if necessary, recalibrated according to manufacturer specifications.

(iii) On-line pH meters shall be calibrated according to manufacturer specifications at least once every 30 days.

(iv) The calibration of on-line pH meters shall be checked at least once each week with a primary standard or by comparing the results from the on-line unit with the results from a properly calibrated benchtop unit. If necessary, the on-line unit shall be recalibrated with primary standards.

(B) Turbidimeters shall be properly calibrated.

(i) Benchtop turbidimeters shall be calibrated with primary standards at least once every 90 days. Each time the turbidimeter is calibrated with primary standards, the secondary standards shall be restandardized.

(ii) The calibration of benchtop turbidimeters shall be checked with secondary standards each time a series of samples is tested, and if necessary, recalibrated with primary standards.

(iii) On-line turbidimeters shall be calibrated with primary standards at least once every 90 days.

(iv) The calibration of on-line turbidimeters shall be checked at least once each week with a primary standard, a secondary standard, or the manufacturer's proprietary calibration confirmation device or by comparing the results from the on-line unit with the results from a properly calibrated benchtop unit. If necessary, the on-line unit shall be recalibrated with primary standards.

(C) Chemical disinfectant residual analyzers shall be properly calibrated.

(i) The accuracy of manual disinfectant residual analyzers shall be verified at least once every 90 days using chlorine solutions of known concentrations.

(ii) The accuracy of continuous disinfectant residual analyzers shall be checked at least once every seven days with a chlorine solution of known concentration or by comparing the results from the on-line analyzer with the result of approved benchtop method in accordance with §290.119 of this title.

(iii) If a disinfectant residual analyzer produces a result which is not within 15% of the expected value, the cause of the discrepancy must be determined and corrected and, if necessary, the instrument must be recalibrated.

(D) Analyzers used to determine the effectiveness of chloramination in §290.110(c)(5) of this title shall be properly verified in accordance with the manufacturer's recommendations every 90 days. These analyzers include monochloramine, ammonia, nitrite, and nitrate equipment used by the public water system.

(E) Ultraviolet (UV) light disinfection analyzers shall be properly calibrated.

(i) The accuracy of duty UV sensors shall be verified with a reference UV sensor monthly, according to the UV sensor manufacturer.

(ii) The reference UV sensor shall be calibrated by the UV sensor manufacturer on a yearly basis, or sooner if needed.

(iii) If used, the UV Transmittance (UVT) analyzer shall be calibrated weekly according to the UVT analyzer manufacturer specifications.

(F) Systems must verify the performance of direct integrity testing equipment in a manner and schedule approved by the executive director.

(G) Conductivity (or total dissolved solids) monitors and pressure instruments used for reverse osmosis and nanofiltration membrane systems shall be calibrated at least once every 12 months.

(H) Any temperature monitoring devices used for reverse osmosis and nanofiltration shall be verified and calibrated in accordance with the manufacturer's specifications.

(t) System ownership. All community water systems shall post a legible sign at each of its production, treatment, and storage facilities. The sign shall be located in plain view of the public and shall provide the name of the water supply and an emergency telephone number where a responsible official can be contacted.

(u) Abandoned wells. Abandoned public water supply wells owned by the system must be plugged with cement according to 16 TAC Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers). Wells that are not in use and are non-deteriorated as defined in those rules must be tested every five years or as required by the executive director to prove that they are in a non-deteriorated condition. The test results shall be sent to the executive director for review and approval. Deteriorated wells must be either plugged with cement or repaired to a non-deteriorated condition.

(v) Electrical wiring. All water system electrical wiring must be securely installed in compliance with a local or national electrical code.

(w) Security. All systems shall maintain internal procedures to notify the executive director by methods provided by the executive director immediately upon determining that one of the following events has occurred, if the event may negatively impact the production or delivery of safe and adequate drinking water:

(1) an unusual or unexplained unauthorized entry at property of the public water system;

(2) an act of terrorism against the public water system;

(3) an unauthorized attempt to probe for or gain access to proprietary information that supports the key activities of the public water system;

(4) a theft of property that supports the key activities of the public water system;

(5) a natural disaster, accident, or act that results in damage to the public water system; or

(6) a nonindustrial water system that experiences an unplanned condition that has caused the system to issue a special precaution under §290.47(e) of this title or issue a do-not-consume advisory, do-not-use advisory, or boil water notice under subsection (q) of this section.

(A) For the purposes of this paragraph, a nonindustrial water system is defined as a public water system which does not exclusively serve industrial connections.

(B) For the purposes of this paragraph unplanned condition is defined as any condition where advance notice to water system customers has not been performed.

(x) Public safety standards. This subsection only applies to a municipality with a population of 1,000,000 or more, with a public utility within its corporate limits; a municipality with a population of more than 36,000 and less than 41,000 located in two counties, one of which is a county with a population of more than 1.8 million; a municipality, including any industrial district within the municipality or its extraterritorial jurisdiction (ETJ), with a population of more than 7,000 and less than 30,000 located in a county with a population of more than 155,000 and less than 180,000; or a municipality, including any industrial district within the municipality or its ETJ, with a population of more than 11,000 and less than 18,000 located in a county with a population of more than 125,000 and less than 230,000.

(1) In this subsection:

(A) "Regulatory authority" means, in accordance with the context in which it is found, either the commission or the governing body of a municipality.

(B) "Public utility" means any person, corporation, cooperative corporation, affected county, or any combination of these persons or entities, other than a municipal corporation, water supply or sewer service corporation, or a political subdivision of the state, except an affected county, or their lessees, trustees, and receivers, owning or operating for compensation in this state equipment or facilities for the transmission, storage, distribution, sale, or provision of potable water to the public or for the resale of potable water to the public for any use or for the collection, transportation, treatment, or disposal of sewage or other operation of a sewage disposal service for the public, other than equipment or facilities owned and operated for either purpose by a municipality or other political subdivision of this state or a water supply or sewer service corporation, but does not include any person or corporation not otherwise a public utility that furnishes the services or commodity only to itself or its employees or tenants as an incident of that employee service or tenancy when that service or commodity is not resold to or used by others.

(C) "Residential area" means:

(i) an area designated as a residential zoning district by a governing ordinance or code or an area in which the principal land use is for private residences;

(ii) a subdivision for which a plat is recorded in the real property records of the county and that contains or is bounded by public streets or parts of public streets that are abutted by residential property occupying at least 75% of the front footage along the block face; or

(iii) a subdivision a majority of the lots of which are subject to deed restrictions limiting the lots to residential use.

(D) "Industrial district" has the meaning assigned by Texas Local Government Code, §42.044, and includes an area that is designated by the governing body of a municipality as a zoned industrial area.

(2) When the regulatory authority is a municipality, it shall by ordinance adopt standards for installing fire hydrants in residential areas in the municipality. These standards must, at a minimum, follow current AWWA standards pertaining to fire hydrants and the requirements of §290.44(e)(6) of this title.

(3) When the regulatory authority is a municipality, it shall by ordinance adopt standards for maintaining sufficient water pressure for service to fire hydrants adequate to protect public safety in residential areas in the municipality. The standards specified in paragraph (4) of this subsection are the minimum acceptable standards.

(4) A public utility shall deliver water to any fire hydrant connected to the public utility's water system located in a residential area so that the flow at the fire hydrant is at least 250 gallons per minute for a minimum period of two hours while maintaining a minimum pressure of 20 psi throughout the distribution system during emergencies such as firefighting. That flow is in addition to the public utility's maximum daily demand for purposes other than firefighting.

(5) When the regulatory authority is a municipality, it shall adopt the standards required by this subsection within one year of the effective date of this subsection or within one year of the date this subsection first applies to the municipality, whichever occurs later.

(6) A public utility shall comply with the standards established by a municipality under both paragraphs (2) and (3) of this subsection within one year of the date the standards first apply to the public utility. If a municipality has failed to comply with the deadline required by paragraph (5) of this subsection, then a public utility shall comply with the standards specified in paragraphs (2) and (4) of this subsection within two years of the effective date of this subsection or within one year of the date this subsection first applies to the public utility, whichever occurs later.

(y) Fire hydrant flow standards.

(1) In this subsection:

(A) "Municipal utility" means a retail public utility, as defined by Texas Water Code (TWC), §13.002, that is owned by a municipality.

(B) "Residential area" means an area used principally for private residences that is improved with at least 100 single-family homes and has an average density of one home per half acre.

(C) "Utility" includes a "public utility" and "water supply or sewer service corporation" as defined by TWC §13.002.

(2) The governing body of a municipality by ordinance may adopt standards set by the executive director requiring a utility to maintain a minimum sufficient water flow and pressure to fire hydrants in a residential area located in the municipality or the municipality's ETJ. The municipality must submit a signed copy of the ordinance to the executive director within 60 days of the adoption of an ordinance by its governing body.

(3) In addition to a utility's maximum daily demand, the utility must provide, for purposes of emergency fire suppression:

(A) a minimum sufficient water flow of at least 250 gallons per minute for at least two hours; and

(B) a minimum sufficient water pressure of at least 20 psi.

(4) If a municipality adopts standards for a minimum sufficient water flow and pressure to fire hydrants, the municipality must require a utility to maintain at least the minimum sufficient water flow and pressure described by paragraph (3) of this subsection in fire hydrants in a residential area located within the municipality or the municipality's ETJ. If the municipality adopts a fire flow standard exceeding the minimum standards set in paragraph (3) of this subsection, the standard adopted by the municipality must be based on:

(A) the density of connections;

(B) service demands; and

(C) other relevant factors.

(5) If the municipality owns a municipal utility, it may not require another utility located in the municipality or the municipality's ETJ to provide water flow and pressure in a fire hydrant greater than that provided by the municipal utility as determined by the executive director.

(6) If the municipality does not own a municipal utility, it may not require a utility located in the municipality or the municipality's ETJ to provide a minimum sufficient water flow and pressure greater than the standard established by paragraph (3) of this subsection.

(7) An ordinance under paragraph (2) of this subsection may not require a utility to build, retrofit, or improve infrastructure in existence at the time the ordinance is adopted.

(8) A municipality with a population of less than 1.9 million that adopts standards under paragraph (2) of this subsection or that seeks to use a utility's water for emergency fire suppression shall enter into a written memorandum of understanding with the utility.

(A) The memorandum of understanding must provide for:

(i) the necessary testing of fire hydrants; and

(ii) other relevant issues pertaining to the use of the water and maintenance of the fire hydrants to ensure compliance with this subsection.

(B) The municipality must submit a signed copy of the memorandum of understanding to the executive director within 60 days of the execution of the memorandum of understanding between its governing body and the utility.

(9) A municipality may notify the executive director of a utility's failure to comply with a standard adopted under paragraph (3) of this subsection.

(10) On receiving the notice described by paragraph (9) of this subsection, the executive director shall require a utility in violation of a standard adopted under this subsection to comply within a reasonable time established by the executive director.

(z) Nitrification Action Plan (NAP). Any water system distributing chloraminated water must create a NAP. The system must create a written NAP that:

(1) contains the system-specific plan for monitoring free ammonia, monochloramine, total chlorine, nitrite, and nitrate levels;

(2) contains system-specific action levels of the above monitored chemicals where action must be taken;

(3) contains specific corrective actions to be taken if the action levels are exceeded; and

(4) is maintained as part of the system's monitoring plan in §290.121 of this title.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 2024.

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Charmaine Backens
Deputy Director, Environmental Law Division
Texas Commission on Environmental Quality
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CHAPTER 291. UTILITY REGULATIONS

The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts amendments to §291.143 and §291.161.

Amended §291.143 and §291.161 are adopted without changes to the proposed text as published in the August 16, 2024, issue of the *Texas Register* (49 TexReg 6165) and, therefore, will not be republished.

Background and Summary of the Factual Basis for the Adopted Rules

During the 88th Texas Legislative Session (2023), House Bill (HB) 1500 and HB 4559 passed, and require amendments to 30 Texas Administrative Code (TAC) Chapter 291 to implement the enacted legislation.

Texas Water Code (TWC), §13.4132, enacted in HB 1500, establishes the duration of an emergency order appointing a temporary manager to operate a utility that discontinues operation or is referred for appointment of a receiver.

This rulemaking reflects changes to TWC, §13.1395 enacted in HB 4559, which amended the definition of "affected utility" by changing county population. The amended population maintains the applicability of the counties required to have an Emergency Preparedness Plan (EPP) under TWC, §13.1395 or TWC, §13.1394.

Section by Section Discussion

§291.143 Operation of a Utility by a Temporary Manager.

The commission adopts amended §291.143 to revise the term limit of a temporary manager from 180 to 360 days, based on the duration of an emergency order, and provide for renewal of the emergency order in accordance with TWC, §13.4132 as amended by HB 1500.

§291.161 Definitions.

The commission adopts amendments to the definition of "affected utility" in §291.161(1)(B)(ii) to change the population from "550,000" to "800,000" in accordance with TWC, §13.1395 as amended by HB 4559. The amended population maintains the applicability of the counties required to have an EPP under TWC, §13.1395 or TWC, §13.1394.

Final Regulatory Impact Determination

The commission reviewed this rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the rulemaking is not subject to §2001.0225. A "Major environmental rule" means a rule with a specific intent to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

First, the rulemaking does not meet the statutory definition of a "Major environmental rule" because its specific intent is not to protect the environment or reduce risks to human health from environmental exposure. The specific intent of the rulemaking is to provide a duration for an emergency order issued under TWC, §13.4132 and to revise the county population in the definition of affected utility in TWC, §13.1395(a)(1), which applies to those affected utilities which are required to submit emergency preparedness plans to the commission for review and approval.

Second, the rulemaking does not meet the statutory definition of a "Major environmental rule" because the rules will not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. It is not anticipated that the cost of complying with the rules will be significant with respect to the economy as a whole or with respect to a sector of the economy; therefore, the amendments will not adversely affect in a material way the economy, a sector of the economy, competition, or jobs.

Finally, the rulemaking does not meet any of the four applicability requirements for a "Major environmental rule" listed in Texas Government Code, §2001.0225(a). Section §2001.0225 only applies to a major environmental rule, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law. This rulemaking does not meet any of the preceding four applicability requirements because this rulemaking: does not exceed any standard set by federal law for public water systems; does not exceed any express requirement of state law; does not exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government; and is not based solely under the general powers of the agency, but under THSC, §341.031 and §341.0315, which allows the commission to adopt and enforce rules related to public drinking water, as well as under the general powers of the commission.

The commission invited public comment regarding the Draft Regulatory Impact Analysis Determination during the public comment period. No comments were received regarding the regulatory impact analysis determination.

Takings Impact Assessment

The commission evaluated this rulemaking and performed a preliminary assessment of whether these rules constitute a taking under Texas Government Code, Chapter 2007.

The commission adopts these rules to implement HB 1500 and 4559, 88th Texas Legislative session (2023). HB 1500 amended TWC, §13.4132 by establishing a duration of 360 days, with the possibility of renewal, for an emergency order issued to appoint a temporary manager of a water system that ceases operation or is referred for appointment of a receiver. HB 4559 amended TWC, §13.1394(a)(1) by changing the county population in the definition of "affected utility." An affected utility is required to file an emergency preparedness plan with the executive director for review and approval.

The commission's analysis indicates that Texas Government Code, Chapter §2007, does not apply to these rules based upon exceptions to applicability in Texas Government Code, §2007.003(b). The rulemaking is an action that is taken to fulfill obligations mandated under state law for all of the adopted rules. The rulemaking related to emergency orders and emergency preparedness plans is also an action taken in response to a real and substantial threat to public health and safety, that is designed to significantly advance the public health and safety purpose, and that does not impose a greater burden than is necessary to achieve the public health and safety purpose. Texas Government Code, §2007.003(b)(4) and (13).

First, the rulemaking is an action taken to fulfill obligations under state law. The duration of an emergency order appointing a temporary manager is now established under TWC, §13.4132(b-1), and the change to the county population in the definition of "affected utility" maintains those affected utilities requirements to submit emergency preparedness plans to the commission under TWC, §13.1395(a)(1).

Second, the rulemaking is related to the duration of emergency orders and to the submission of emergency preparedness plans by affected utilities, which are actions that are taken in response to a real and substantial threat to public health and safety. The adopted rules will ensure the continuity of operation of public water systems by temporary managers appointed pursuant to emergency orders with a duration established by the legislature and by ensuring that emergency preparedness plans are submitted by affected utilities in appropriate counties designated by the legislature. The adopted rules will significantly advance the public health and safety purpose; and does not impose a greater burden than is necessary to achieve the public health and safety purpose. These rules advance the public health and safety by ensuring appropriate governmental regulation and do so in a way that does not impose a greater burden than is necessary to achieve the public health and safety purpose. Texas Government Code, §2007.003(b)(13).

Further, the commission has determined that promulgation and enforcement of these rules will be neither a statutory nor a constitutional taking of private real property. Specifically, there are no burdens imposed on private real property under the rules because the rules neither relate to, nor have any impact on, the use or enjoyment of private real property, and there will be no reduction in property value as a result of these rules. The rules require compliance regarding the duration of an emergency order appointing a temporary manager as now established under state law, and compliance regarding submission by an affected utility to the commission of its emergency preparedness plan, which is meant to ensure public health and safety. Therefore, the rules will not constitute a taking under Texas Government Code, Chapter §2007.

Consistency with the Coastal Management Program

The commission reviewed the adopted rulemaking and found that the sections proposed for amendments are neither identified in Coastal Coordination Act implementation rules, 31 TAC §505.11(b)(2) or (4), nor will the amendments affect any action or authorization identified in Coastal Coordination Act implementation rules, 31 TAC §505.11(a)(6). Therefore, the adopted rulemaking is not subject to the Texas Coastal Management Program.

The commission invited public comment regarding the consistency with the coastal management program during the public comment period. No comments were received regarding the Coastal Management Program.

Public Comment

The commission held a public hearing on Thursday, September 12, 2024. No oral comments were received at the public hearing. The comment period closed on Tuesday, September 17, 2024. The commission received timely comments on the proposed Chapter §290 rules from Texas Rural Water Association (TRWA) but received no comments on the proposed Chapter §291 rules.

SUBCHAPTER J. ENFORCEMENT, SUPERVISION, AND RECEIVERSHIP

30 TAC §291.143

Statutory Authority

The rulemaking is adopted under Texas Water Code (TWC), §5.013, which establishes the general jurisdiction of the commission; TWC, §5.102, which establishes the commission's general authority to perform any act necessary to carry out its jurisdiction; TWC, §5.103 and TWC, §5.105, which establish the commission's authority to adopt any rules necessary to carry out its powers and duties; Texas Health and Safety Code (THSC), §341.031, which requires drinking water supplies to meet standards established by the commission; and THSC, §341.0315, which requires public drinking water systems to comply with commission standards established to ensure the supply of safe drinking water.

The rulemaking adoption implements legislation enacted by the 88th Texas Legislature in 2023: TWC, §13.4132 in House Bill (HB) 1500 and TWC, §13.1395(a)(1) in HB 4559.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Charmaine Backens

Deputy Director, Environmental Law Division

Texas Commission on Environmental Quality

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For further information, please call: (512) 239-2678

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SUBCHAPTER L. STANDARDS OF EMERGENCY OPERATIONS

30 TAC §291.161

Statutory Authority

The rulemaking is adopted under Texas Water Code (TWC) §5.013, which establishes the general jurisdiction of the commission; TWC §5.102, which establishes the commission's general authority to perform any act necessary to carry out its jurisdiction; TWC §5.103 and TWC §5.105, which establish the commission's authority to adopt any rules necessary to carry out its powers and duties; Texas Health and Safety Code (THSC) §341.031, which requires drinking water supplies to meet standards established by the commission; and THSC §341.0315, which requires public drinking water systems to comply with commission standards established to ensure the supply of safe drinking water.

The rulemaking adoption implements legislation enacted by the 88th Texas Legislature in 2023: TWC §13.4132 in House Bill (HB) 1500 and TWC §13.1395(a)(1) in HB 4559.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 331. UNDERGROUND INJECTION CONTROL

The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts amendments to §331.11 and §331.132.

Amended §331.11 and §331.132 are adopted without changes to the proposed text as published in the August 2, 2024, issue of the *Texas Register* (49 TexReg 5746) and, therefore, will not be republished.

Background and Summary of the Factual Basis for the Adopted Rules

This rulemaking adoption implements Senate Bill (SB) 786 and SB 1186, 88th Texas Legislature, 2023, addressing agency jurisdiction over regulation of closed-loop geothermal injection wells and agency jurisdiction over brine mining injection wells in Texas. SB 786 confers the Railroad Commission of Texas (RRC) with jurisdiction over the regulation of closed-loop geothermal injection wells. SB 1186 confers the RRC with jurisdiction over the regulation of brine mining and the injection wells used for brine mining.

This rulemaking adoption implements SB 786 by amending the commission's underground injection control rules to remove requirements for the regulation of closed-loop geothermal injection wells. Prior to the enactment of SB 786, the commission's underground injection control rules included geothermal closed-loop injection wells as a type of Class V injection well under the jurisdiction of the commission. SB 786 provides that all commission functions and activities that relate to the regulation of closed-loop geothermal injection wells are transferred to the RRC. The RRC plans to implement SB 786 through adoption of their own rules relating to Class V closed-loop geothermal injection wells.

The rulemaking adoption implements SB 1186 by amending the commission's underground injection control rules to acknowledge that the RRC has jurisdiction over the regulation of Class V injection wells used for brine mining. SB 1186 defines "brine mining" as the "production of brine, including naturally occurring brine and brine extracted by the solution of a subsurface salt formation, for the purpose of extracting from a subsurface formation elements, salts, or other useful substances...." SB 1186 defines a "Class V brine injection well" as a "well that injects spent, naturally occurring brine produced by a brine mining operation into the same formation from which it was withdrawn after extraction of elements, salts or other useful substances, including halogens or halogens salts."

Section by Section Discussion

The commission adopts amendment of 30 Texas Administrative Code (TAC) §331.11 by removing subsection (a)(4)(B), which states "closed loop injection wells which are closed system geothermal wells used to circulate fluids including water, water with additives, or other fluids or gases through the earth as a heat source or heat sink;" and re-lettering the remainder of the paragraph. The adopted amendment to remove §331.11(a)(4)(B) implements Texas Water Code (TWC), §27.037 as established in SB 786 by removing the inclusion of closed-loop geothermal injection wells as a type of Class V injection well for which the commission has jurisdiction.

The commission adopts amendment of 30 TAC §331.11(b) to implement SB 786 and SB 1186 and provisions of TWC, Chapter 27. The commission adopts amendment of §331.11(b) to identify certain types of injection wells for which the RRC has jurisdiction to regulate. Under TWC §27.011, the commission has jurisdiction over the regulation of injection wells unless the activity is subject to the jurisdiction of the RRC. The commission has jurisdiction over the Class III injection wells classified in 30 TAC §331.11(a)(2) and the Class V injection wells classified in TAC §331.11(a)(4). The RRC has jurisdiction to regulate Class II injection wells under TWC, §27.031 and §27.0511. The RRC has jurisdiction over Class III and Class V injection wells used for brine mining as established in TWC, §27.036 and SB 1186. The RRC has jurisdiction over injection wells used for in situ recovery of tar sands as established in TWC, §27.035. The RRC has jurisdiction over injection wells used for the exploration, development or production of geothermal energy, including closed-loop geothermal injection wells as established in Texas Natural Resources Code Chapter 141, TWC, §27.037, and SB 786. The RRC has jurisdiction over the injection and geologic storage of carbon dioxide as established in TWC, §27.041.

The commission adopts amendment of 30 TAC §331.132(d)(3) by correcting a typographical error, changing "...close loop..." to "...closed loop...." References to closed-loop injection wells in §331.132 will apply to other types of closed-loop injection systems but not closed-loop geothermal injection wells regulated by the RRC.

Final Regulatory Impact Analysis

The commission reviewed the rulemaking action in light of the regulatory analysis requirements of Texas Government Code (TGC), §2001.0225, and determined that the action is not subject to TGC, §2001.0225 because it does not meet the definition of a "Major environmental rule" as defined in that statute. A "major environmental rule" is a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The adopted amendments implement state legislation that confers RRC with jurisdiction over certain types of injection wells and activities. The adopted rules remove commission requirements for the regulation of closed-loop geothermal injection wells and recognize the RRC as the regulatory agency for the regulation of closed-loop geothermal injection wells and Class V brine mining injection wells. The adopted rules are not specifically intended to protect the environment or reduce risks to human health from environmental exposure, nor does it affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

As defined in the TGC, §2001.0225 only applies to a major environmental rule, the result of which is to: exceed a standard set by federal law, unless the rule is specifically required by state law; exceed an express requirement of state law, unless the rule is specifically required by federal law; exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or adopt a rule solely under the general authority of the commission. The adopted amendments do not exceed a standard set by federal law. The adopted amendments do not exceed an express requirement of state law or a requirement of a delegation agreement. These rules were not developed solely under the general powers of the agency but are authorized by specific sections of the Texas Water Code that are cited in the statutory authority section of this preamble. Therefore, this rulemaking is not subject to the regulatory analysis provisions of TGC, §2001.0225(b).

The commission invited public comment regarding the Draft Regulatory Impact Analysis Determination during the public comment period. No comments were received regarding the regulatory impact analysis determination.

Takings Impact Assessment

The commission evaluated the rulemaking and performed an analysis of whether the adopted rules constitute a taking under TGC, Chapter 2007. The specific purpose of the adopted amendments to Chapter 331 is to remove requirements for closed-loop geothermal injection wells in commission rule and recognize RRC jurisdiction over certain injection well activities. The adopted rulemaking substantially advances these stated purposes by implementing rules that reflect agency jurisdiction over injection wells as reflected in Texas statutes.

The commission's analysis indicates that the adopted rules will be neither a statutory nor a constitutional taking of private real property. Specifically, the amended rules do not affect a landowner's rights in real property because the adopted rulemaking does not burden (constitutionally); nor restrict or limit the owner's right to property and reduce its value by 25% or more beyond that which would otherwise exist in the absence of the regulations. The adopted amendments in Chapter 331 do not impose requirements on the owners of real property. The adopted amendments in Chapter 331 do not affect private real property in a manner that restricts or limits an owner's right to the property that will otherwise exist in the absence of the rulemaking. The adopted rulemaking will assist the public by implementing rules that are consistent with the Legislature's designation of agency responsibility for the regulation of injection wells in Texas.

Consistency with the Coastal Management Program

The commission reviewed the adopted rules and found they are neither identified in Coastal Coordination Act Implementation Rules, 31 TAC §29.11(b)(2) or (4), nor will they affect any action/authorization identified in Coastal Coordination Act Implementation Rules, 31 TAC §29.11(a)(6). Therefore, the adopted rules are not subject to the Texas Coastal Management Program.

The commission invited public comment regarding the consistency with the coastal management program during the public comment period. No comments were received regarding the CMP.

Public Comment

The commission offered a public hearing on August 29, 2024. The comment period closed on September 3, 2024. The commission received comments from Michael Mecke.

Response to Comment

Comment

Michael Mecke commented that the rules could have major effects on groundwater and should be addressed by the Texas Water Development Board (TWDB). Michael Mecke commented that water issues should be addressed by water agencies, such as the TWDB, and not mixed in with oil and gas regulations and issues.

Response

The adopted rules reflect the Texas Legislature's designation of agency responsibility for the regulation of injection wells. Under the Injection Well Act, only the commission and the RRC are conferred jurisdiction over the regulation of injection wells. The TWDB does not have jurisdiction over the regulation of injection wells. The adopted rules implement SB 786 and SB 1186 by recognizing RRC jurisdiction over closed-loop geothermal injection wells and injection wells used for brine mining. No changes were made in response to the comment.

SUBCHAPTER A. GENERAL PROVISIONS

30 TAC §331.11

Statutory Authority

The amendments are adopted under Texas Water Code (TWC), Chapter 5, §5.013, which establishes the general jurisdiction of the commission; §5.102, which provides the commission with the authority to carry out its duties and general powers under its jurisdictional authority as provided by TWC; §5.103, which requires the commission to adopt any rule necessary to carry out its powers and duties under the TWC and other laws of the state; and §27.019, which authorizes the commission to adopt rules for the performance of its powers, duties, and functions under the Injection Well Act.

The adopted rules implement Senate Bill (SB) 786 and SB 1186, 88th Texas Legislature, 2023; TWC, §§27.011; 27.031; 27.035; 27.036; 27.037; 27.041; and 27.0511.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER H. STANDARDS FOR CLASS V WELLS

30 TAC §331.132

Statutory Authority

The amendments are adopted under Texas Water Code (TWC), Chapter 5, §5.013, which establishes the general jurisdiction of the commission; §5.102, which provides the commission with the authority to carry out its duties and general powers under its jurisdictional authority as provided by TWC; §5.103, which requires the commission to adopt any rule necessary to carry out its powers and duties under the TWC and other laws of the state; and §27.019, which authorizes the commission to adopt rules for the performance of its powers, duties, and functions under the Injection Well Act.

The adopted rules implement Senate Bill (SB) 786 and SB 1186, 88th Texas Legislature, 2023; and TWC, §§27.011, 27.031, 27.035, 27.036, 27.037, 27.041, and 27.0511.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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TITLE 31. NATURAL RESOURCES AND CONSERVATION

PART 10. TEXAS WATER DEVELOPMENT BOARD

CHAPTER 356. GROUNDWATER MANAGEMENT

The Texas Water Development Board (TWDB) adopts amendments in 31 Texas Administrative Code (TAC) Subchapters A, B, C, E, and G, more specifically §§356.10, 356.20, 356.22, 356.31 - 356.35, 356.51 - 356.57, and 356.70 - 356.72. The rules are adopted with changes as published in the August 9, 2024, issue of the *Texas Register* (49 TexReg 5914). The rules will be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED AMENDMENT.

The TWDB adopts this rulemaking updating and clarifying rule language that will facilitate groundwater management in the state and related requirements for groundwater conservation districts. The adopted rule language adds specificity and clarity regarding desired future condition packages, including non-relevant aquifer documentation; required elements of groundwater management plans; and brackish groundwater production zones. Additionally, the TWDB adds new definitions for brackish groundwater, conservation, groundwater management area, and non-relevant aquifer.

SECTION BY SECTION DISCUSSION OF ADOPTED AMENDMENTS.

31 TAC 356, Subchapter A

The adopted amendments in §356.10, Definitions, adds the following new definitions: "brackish groundwater" in §356.10(5), "conservation" in §356.10(9), "groundwater management area" in §356.10(15), and "non-relevant aquifer" in §356.10(21). Other adopted amendments to §356.10 include correcting an error in §356.10(3) to refer to the "quantity" of water rather than the "quality" of water, renumbering the entire section to provide for new definitions, and to clarify rule language improving the readability of the rule.

31 TAC 356, Subchapter B

The adopted amendments in §§356.20 and 356.22 modernize the rule language. No changes are adopted to §356.21 and that rule will not be published with this adoption.

31 TAC 356, Subchapter C

No changes are adopted to §356.30. That rule will not be published with this adoption.

The adopted amendments in §356.31 update the title of the section and the due date by which desired future condition packages are due from a designated representative of each groundwater management area to the Executive Administrator of the TWDB. The adopted amendments also clarify "non-relevant" aquifer designations and required documentation submitted as part of a desired future condition package.

The adopted amendments in §356.32 update the title of the section, clarify the contents of the submission package for desired future conditions due to the TWDB, requires the submission of "non-relevant" aquifer information, and renumbers the section, as appropriate.

The adopted amendments in §356.33 require that a package submitting a desired future condition by the representative of a groundwater management area be signed and dated by that representative. The adopted amendments also clarify how the Executive Administrator of the TWDB will determine whether a submission package is administratively complete.

The adopted amendments in §356.34 modernize the rule language.

The adopted amendments in §356.35 clarify that a desired future condition package is what is declared administratively complete by the Executive Administrator.

31 TAC 356, Subchapter E

No changes are adopted to §356.50, and the rule will not be republished with this adoption.

The adopted amendments in §356.51 modernize the rule language.

The adopted amendments in §356.52 clarify that "management objectives," must correspond to a "management goal," to include adopted §356.52(a)(5) in the review of submitted management plans. Adopted amendments to this section also include §356.52(a)(7) requiring a consideration of water supply needs and water management strategies, in accordance with statute, and to modernize and re-number the rule language throughout the section.

The adopted amendments in §356.53 modernize the rule language, update the kind of information submitted to the Executive Administrator during review of a management plan, and reflect that documentation of notice of the plan's adoption may be posted on the official website of a District. Section 356.53(a)(1) removes the requirement for hard-copy submissions of adopted management plans and provide for only the submission of electronic versions of adopted management plans.

The adopted amendments in §356.54 clarify that management plans are "revised" rather than "amended" when an adopted plan is not approved by the Executive Administrator.

The adopted amendments in §356.55 modernize the rule language.

The adopted amendments in §356.56 update the title of the section, adds new §356.56(a) clarifying the process of Executive Administrator approval of amended management plans, to provide that changes to approved management plans will be defined as "amendments" rather than "addendums," and to re-number the section.

The adopted amendments in §356.57 update the rule language.

31 TAC 356 Subchapter G

The adopted amendments in §356.70 update the language and update §356.70(d), providing the TWDB authority to amend a designated brackish groundwater production zone on its own, or by request by a district. In addition, §356.70(e) requires the TWDB to provide public notice of an amendment related to a designated brackish groundwater production zone.

The adopted amendments in §356.71 updates the rule language.

The adopted amendments in §356.72 requires districts to submit certain report information to the TWDB and clarifies and updates the rule language.

REGULATORY IMPACT ANALYSIS DETERMINATION (Texas Government Code §2001.0225)

The TWDB reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government Code §2001.0225 and determined that the rulemaking is not subject to Texas Government Code §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in the Administrative Procedure Act. A "major environmental rule" is defined as a rule with the specific intent to protect the environment or reduce risks to human health from environmental exposure, a rule that may adversely affect, in a material way, the economy or a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The intent of the rulemaking is to update and clarify existing rules that are necessary for groundwater management in the state and certain requirements for groundwater conservation districts.

Even if the adopted rulemaking were a major environmental rule, Texas Government Code §2001.0225 still would not apply to this rulemaking because Texas Government Code §2001.0225 only applies to a major environmental rule, the result of which is to: (1) exceed a standard set by federal law, unless the rule is specifically required by state law; (2) exceed an express requirement of state law, unless the rule is specifically required by federal law; (3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or (4) adopt a rule solely under the general powers of the agency instead of under a specific state law. This rulemaking does not meet any of these four applicability criteria because it: (1) does not exceed any federal law; (2) does not exceed an express requirement of state law; (3) does not exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; and (4) is not proposed solely under the general powers of the agency, but rather Texas Water Code §15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011. Therefore, this adopted rulemaking does not fall under any of the applicability criteria in Texas Government Code §2001.0225.

TAKINGS IMPACT ASSESSMENT (Texas Government Code §2007.043)

The TWDB evaluated this adopted rulemaking and performed an analysis of whether it constitutes a taking under Texas Government Code, Chapter 2007. The specific purpose of this rulemaking is to update and clarify existing rules that are necessary for groundwater management in the state and certain requirements for groundwater conservation districts. The adopted rulemaking will substantially advance this stated purpose by aligning definitions with agency and industry practice and providing greater detail for desired future condition packages and required elements of groundwater management plans.

The TWDB's analysis indicates that Texas Government Code, Chapter 2007 does not apply to this adopted rulemaking because this is an action that is reasonably taken to fulfill an obligation mandated by state law, which is exempt under Texas Government Code §2007.003(b)(4). The TWDB is the agency charged with the delineation of groundwater management areas in order to assist with the conservation, preservation, protection, and prevention of the waste of the state's groundwater resources.

Nevertheless, the TWDB further evaluated this adopted rulemaking and performed an assessment of whether it constitutes a taking under Texas Government Code Chapter 2007. Promulgation and enforcement of this adopted rulemaking would be neither a statutory nor a constitutional taking of private real property. Specifically, the subject proposed regulation does not affect a landowner's rights in private real property because this rulemaking does not burden, restrict, or limit the owner's right to property and reduce its value by 25% or more beyond that which would otherwise exist in the absence of the regulation. In other words, this rulemaking updates the state's existing rules that facilitate groundwater management without burdening or restricting or limiting the owner's right to property and reducing its value by 25% or more. Therefore, the adopted rulemaking does not constitute a taking under Texas Government Code, Chapter 2007.

PUBLIC COMMENTS (Texas Government Code §2001.033(a)(1))

The following comments were received from Adam Foster, the Executive Director for the Texas Alliance of Groundwater Districts. The public comment period for this rulemaking ended on September 9, 2024. The following is a compilation of the comments received including a response to each.

Comment:

Adam Foster, Executive Director of Texas Alliance of Groundwater Districts (TAGD) commented that TAGD had concerns about the proposed definition of "brackish" and the "potential to designated significant portions of aquifers, such as the Blaine Aquifer, as brackish." He noted that the proposed definition appeared to be intended to be limited for "Brackish Groundwater Production Zones." He additionally recommended further clarification about the proposed rule.

Response:

The TWDB acknowledges these comments. The added definition of "brackish groundwater" is for the purposes of brackish groundwater production zone designations under Texas Water Code §16.060 and includes the salinity range used currently for zone designations.

The TWDB does not designate zones in areas that meet exclusionary criteria described in Texas Water Code §16.060(b)(5). Areas expressly excluded from zone designations include: 1) the Edwards Aquifer located within the jurisdictional boundaries of the Edwards Aquifer Authority, the Barton Springs-Edwards Aquifer Conservation District, the Harris Galveston Subsidence District, and the Fort Bend Subsidence District; 2) aquifers, subdivisions of aquifers, or geologic strata that have an average total dissolved solids concentration of more than 1,000 milligrams per liter which serve as a significant source of water supply for municipal, domestic, or agricultural purposes; and 3) geologic formations that are designated or used for wastewater injection through the use of injection or disposal wells permitted under Texas Water Code Chapter 27.

The TWDB completed a brackish aquifer study for the Blaine Aquifer in 2016 and did not designate any brackish groundwater production zones due to the exclusionary criteria, including that the aquifer serves as significant source of water for domestic and agricultural purposes.

The TWDB added the statutory reference for brackish groundwater production zone designations to the definition of brackish groundwater in response to this comment.

Comment:

Adam Foster also commented whether the proposed definition of conservation could be expanded to include the enhancement of recharge.

Response:

The TWDB acknowledges these comments. The definition of "conservation" is consistent with the definition in Texas Water Code §15.001(9)(B) and was added to define the conservation goal that must be addressed in a groundwater management plan. The goal related to conservation also includes recharge enhancement, rainwater harvesting, precipitation enhancement, and brush control (Texas Water Code §36.1071(a)(8)). The TWDB made no changes to the rule in response to this comment.

Comment:

Adam Foster also submitted comments on behalf of TAGD about 31 TAC Section 356.52(a)(7), specifically about the addition to "consider water supply needs in the water plan." TAGD seeks clarification for the proposed addition to the rule.

Response:

Groundwater conservation districts are currently required by Texas Water Code §36.1071(e)(4), to consider the water supply needs and water management strategies in the state water plan. The purpose of this proposed amendment is to emphasize the focus on considering the needs and strategies that potentially impact groundwater supplies or can be impacted by district actions. The TWDB routinely provides guidance during pre-reviews of management plans before final approval. The TWDB made no changes to the rule in response to these comments.

Comment:

Adam Foster of TAGD commented about changes to 31 TAC §356.56, stating that groundwater conservation districts "have encountered difficulties with 5-year adoption periods not being reset with the MAG generation by TWDB and aligning their management plan cycle." Additionally, TAGD "recommends adjusting the management plan cycle to begin following the release of MAG updates, as opposed to DFCs."

Response:

The TWDB acknowledges these comments. A groundwater conservation district may reset their 5-year management plan adoption cycle at any time by submitting a fully updated groundwater management plan to the TWDB for review and approval. Texas Water Code §36.3011(b)(5) alludes to the requirement that a groundwater conservation district must update its groundwater management plan before the second anniversary of the adoption of desired future conditions by the groundwater management area. Any efforts to require an updated management plan following the distribution of modeled available groundwater estimates rather than the date desired future conditions are adopted within a groundwater management area would require a statutory change that is outside the scope of this rulemaking. The TWDB made no changes to the rule in response to these comments.

SUBCHAPTER A. DEFINITIONS

31 TAC §356.10

STATUTORY AUTHORITY (Texas Government Code §2001.033(a)(2))

The amendment is adopted under the authority of Texas Water Code §6.101, which provides the TWDB with the authority to adopt rules necessary to carry out the powers and duties in the Water Code and other laws of the State, and also under the authority of Water Code §§15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085.

This rulemaking affects Texas Water Code, §15.001 §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011.

§356.10. Definitions.

The following words and terms, when used in this chapter, will have the following meanings unless the context clearly indicates otherwise. Words defined in Texas Water Code Chapter 36, Groundwater Conservation Districts, that are not defined here will have the meanings provided in Chapter 36.

(1) Affected Person--An owner of land in the management area, a district in or adjacent to the management area, a regional water planning group with a water management strategy in the management area, a person or entity who holds or is applying for a permit from a district in the management area, a person or entity who has groundwater rights in the management area or any other person defined as affected with respect to a management area by Texas Commission on Environmental Quality rule.

(2) Agency--The Texas Water Development Board.

(3) Amount of groundwater being used on an annual basis--An estimate of the quantity of groundwater annually withdrawn or flowing from wells in an aquifer for at least the most recent five years that information is available. It may include data from Texas Water Development Board historical water use estimates, an estimate of exempt uses, and data collected by the district.

(4) Board--The governing body of the Texas Water Development Board.

(5) Brackish groundwater--Groundwater containing 1,000 to 9,999 milligrams per liter of total dissolved solids for the purposes of brackish groundwater production zone designations under Texas Water Code §16.060.

(6) Brackish groundwater production zone operating permit--A permit issued by a district under Texas Water Code §36.1015.

(7) Conjunctive use--The combined use of groundwater and surface water sources that optimizes the beneficial characteristics of each source, such as water banking, aquifer storage and recovery, enhanced recharge, and joint management.

(8) Conjunctive surface water management issues--Issues related to conjunctive use such as groundwater or surface water quality degradation and impacts of shifting between surface water and groundwater during shortages.

(9) Conservation-- Practices, techniques, and technologies that will reduce the consumption of water, reduce the loss or waste of water, improve the efficiency in the use of water, or increase the recycling and reuse of water so that a water supply is made available for future or alternative uses.

(10) Designated brackish groundwater production zone--An aquifer, subdivision of an aquifer, or geologic stratum designated under Texas Water Code §16.060(b)(5).

(11) Desired future condition--The desired, quantified condition of groundwater resources (such as water levels, spring flows, or volumes) within a groundwater management area at one or more specified future times as defined by district representatives within a groundwater management area as part of the joint planning process.

(12) District--Any district or authority subject to Chapter 36, Texas Water Code.

(13) Executive administrator--The executive administrator of the Texas Water Development Board or a designated representative.

(14) Groundwater availability model--A regional groundwater flow model provided by the executive administrator.

(15) Groundwater management area--An area delineated and designated by the Texas Water Development Board as an area most suitable for management of groundwater resources through regional joint groundwater planning.

(16) Major aquifer--An aquifer designated as a major aquifer by the board.

(17) Minor aquifer--An aquifer designated as a minor aquifer by the board.

(18) Modeled available groundwater--The amount of water that the executive administrator determines may be produced on an average annual basis to achieve a desired future condition.

(19) Most efficient use of groundwater--Practices, techniques, and technologies that a district determines will provide the least consumption of groundwater for each type of use balanced with the benefits of using groundwater.

(20) Natural resources issues--Issues related to environmental and other concerns that may be affected by a district's groundwater management plan and rules, such as impacts on endangered species, soils, oil and gas production, mining, air and water quality degradation, agriculture, and plant and animal life.

(21) Non-relevant aquifer--An aquifer or portion of an aquifer deemed not relevant for joint planning purposes by district representatives within a groundwater management area.

(22) Office--State Office of Administrative Hearings.

(23) Petition--A document submitted to a district by an affected person appealing the reasonableness of a desired future condition.

(24) Projected water demand--The quantity of water needed on an annual basis according to the state water plan for the state water plan planning period.

(25) Recharge enhancement--Increased recharge accomplished by the modification of the land surface, streams, or lakes to increase seepage or infiltration rates or by the direct injection of water into the subsurface through wells.

(26) Relevant aquifer--An aquifer designated as a major or minor aquifer, or any undesignated aquifer deemed relevant for joint planning by district representatives within a groundwater management area.

(27) State water plan--The most recent state water plan adopted by the board under Texas Water Code §16.051 (relating to State Water Plan).

(28) Surface water management entities--Political subdivisions as defined by Texas Water Code Chapter 15 and identified from Texas Commission on Environmental Quality records that are granted authority under Texas Water Code Chapter 11 to store, take, divert, or supply surface water either directly or by contract for use within the boundaries of a district, including but not limited to river authorities or irrigation authorities.

(29) Total estimated recoverable storage--The estimated amount of groundwater within an aquifer that accounts for recovery scenarios that range between 25% and 75% of the porosity-adjusted aquifer volume.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Ashley Harden
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SUBCHAPTER B. DESIGNATION OF GROUNDWATER MANAGEMENT AREAS

31 TAC §356.20, §356.22

STATUTORY AUTHORITY (Texas Government Code §2001.033(a)(2))

The amendments are adopted under the authority of Texas Water Code §6.101, which provides the TWDB with the authority to adopt rules necessary to carry out the powers and duties in the Water Code and other laws of the State, and also under the authority of Water Code §§15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085.

This rulemaking affects Texas Water Code, §15.001 §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011.

§356.20. Scope of Subchapter.

This subchapter describes the agency's delineation and designation of groundwater management areas pursuant to the requirements of Texas Water Code §35.004.

§356.22. Request to Amend Groundwater Management Area Boundaries.

(a) A request to amend the boundaries of a groundwater management area must be made in writing to the executive administrator and must contain the following:

(1) a resolution supporting the change signed by each of the district representatives in each affected groundwater management area;

(2) a demonstration that the geographic and hydrogeologic conditions require the proposed boundary change or an explanation that the change involves only an administrative correction; and

(3) a copy of the notice and minutes of the public meeting held by the districts in each affected groundwater management area at which the districts approved the resolution in paragraph (1) of this subsection.

(b) The executive administrator will review the request and will notify the districts of his decision.

(1) If the proposed change involves only an administrative adjustment or correction to the boundary data files identified in §356.21 of this subchapter (relating to Designation of Groundwater Management Areas), the executive administrator will instruct agency staff to make the change and notify the districts upon completing the change.

(2) If the proposed change involves a substantive change to the boundaries of one or more groundwater management areas, the request will be presented to the board for authorization.

(c) The executive administrator may, in his discretion, make administrative corrections to the data files described in §356.21 of this subchapter. The executive administrator will notify the affected districts before making any correction.

(d) The executive administrator may, in his discretion, waive any of the requirements of this subchapter upon a showing of good cause.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER C. SUBMISSION OF DESIRED FUTURE CONDITIONS

31 TAC §§356.31 - 356.35

STATUTORY AUTHORITY (Texas Government Code §2001.033(a)(2))

The amendments are adopted under the authority of Texas Water Code §6.101, which provides the TWDB with the authority to adopt rules necessary to carry out the powers and duties in the Water Code and other laws of the State, and also under the authority of Water Code §§15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085.

This rulemaking affects Texas Water Code, §15.001 §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011.

§356.31. Desired Future Condition Package Submission Date.

(a) The desired future conditions for the relevant aquifers within the groundwater management area must be approved by a resolution adopted by a two-thirds vote of all the district representatives in a groundwater management area not later than January 5, 2027, in accordance with Texas Water Code §36.108. Subsequent desired future conditions must be proposed and finally adopted by the district representatives before the end of each successive five-year period after that date.

(b) A designated representative of the groundwater management area must provide complete copies of all documents required under §356.32 of this subchapter (relating to Desired Future Condition

Package) to the executive administrator no later than 60 days following the date on which the district representatives within the groundwater management area adopted desired future conditions.

(c) The district representatives in a groundwater management area may, as part of the process for adopting and submitting desired future conditions, propose classification of a relevant aquifer or portions of a relevant aquifer as non-relevant if the districts determine that aquifer characteristics, projected groundwater demands, and current groundwater uses do not warrant adoption of a desired future condition. Non-relevant aquifers do not require a desired future condition. The districts must submit the following documentation for non-relevant aquifers to the agency as part of the desired future condition package:

(1) A description, location, and/or map of the aquifer or portion of the aquifer;

(2) A summary of aquifer characteristics, projected groundwater demands, and current groundwater uses, including the total estimated recoverable storage as provided by the executive administrator, that support the conclusion that desired future conditions in adjacent or hydraulically connected relevant aquifer(s) will not be affected; and

(3) An explanation of why the aquifer or portion of the aquifer is non-relevant for joint planning purposes.

§356.32. Desired Future Condition Package.

A designated representative of the groundwater management area must provide the following to the executive administrator no later than 60 days following the date on which the district representatives in the groundwater management area adopted the desired future condition(s):

(1) a copy of the desired future conditions explanatory report addressing the information required by Texas Water Code §36.108(d-3) and the criteria in Texas Water Code §36.108(d);

(2) non-relevant aquifer documentation required by §356.31(c) of this subchapter (relating to Desired Future Condition Package Submission Date);

(3) a copy of the resolution of the groundwater management area adopting the desired future conditions as required by Texas Water Code §36.108(d-3);

(4) a copy of the notice that was posted for the joint planning meeting at which the districts collectively adopted the desired future condition(s) as required by Texas Water Code §36.108(e) and §36.108(e-2);

(5) the name of a designated representative of the groundwater management area;

(6) any groundwater availability model files or aquifer assessments acceptable to the executive administrator used in developing the adopted desired future condition with documentation sufficient to replicate the work; and

(7) any other information the executive administrator may require to be able to estimate the modeled available groundwater.

§356.33. Determination of Administrative Completeness.

A submitted package will be considered administratively complete if it contains complete copies of all documents required under §356.32 of this subchapter (relating to Desired Future Condition Package) and is signed and dated by the designated representative of the groundwater management area.

(1) The executive administrator will acknowledge in writing receipt of submitted packages and will review for administrative completeness. The agency may request clarifications while reviewing the package for administrative completeness. If the submitted package is administratively complete, the executive administrator will notify the district representatives within the groundwater management area in writing. If requests for clarification are not acknowledged or addressed in a reasonable amount of time, the executive administrator will provide a notice of deficiencies.

(2) The designated representative of the groundwater management area must submit to the executive administrator an updated package that contains corrections to the deficiencies noted in paragraph (1) of this section no later than 90 days following the date on which the executive administrator provided a notice of deficiencies.

§356.34. District Adoption of the Desired Future Condition.

Each district must adopt the desired future condition for the aquifer(s) within its boundaries as soon as possible after the executive administrator advises that the desired future condition package submitted pursuant to §356.32 of this subchapter (relating to Desired Future Condition Package) is administratively complete.

§356.35. Modeled Available Groundwater.

The executive administrator will provide the modeled available groundwater value for each relevant aquifer with a desired future condition to districts in a groundwater management area and the appropriate regional water planning groups no later than 180 days after the executive administrator has provided notice that the submitted desired future condition package is administratively complete as described in §356.33 of this subchapter (relating to Determination of Administrative Completeness).

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER E. GROUNDWATER MANAGEMENT PLAN APPROVAL

31 TAC §§356.51 - 356.57

STATUTORY AUTHORITY (Texas Government Code §2001.033(a)(2))

The amendments are adopted under the authority of Texas Water Code §6.101, which provides the TWDB with the authority to adopt rules necessary to carry out the powers and duties in the Water Code and other laws of the State, and also under the authority of Water Code §§15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085.

This rulemaking affects Texas Water Code, §15.001 §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011.

§356.51. Required Management Plan.

In accordance with Texas Water Code §§36.1071 (including coordination with surface water management entities on a regional basis), 36.1072, and 36.1085, a district must develop and submit to the executive administrator a management plan that meets the requirements of §356.52 of this subchapter (relating to Required Content of Management Plan).

§356.52. Required Content of Management Plan.

(a) A management plan must contain, unless explained in detail as not applicable, the following elements:

(1) Management goals:

(A) providing the most efficient use of groundwater;

(B) controlling and preventing waste of groundwater;

(C) controlling and preventing subsidence;

(D) addressing conjunctive surface water management issues;

(E) addressing natural resource issues which impact the use and availability of groundwater, and which are impacted by the use of groundwater;

(F) addressing drought conditions;

(G) addressing conservation, recharge enhancement, rainwater harvesting, precipitation enhancement and brush control, where appropriate and cost-effective; and

(H) addressing the desired future conditions adopted by the district under Texas Water Code §36.108;

(2) Management objective(s) for each management goal. Management objectives are specific, measurable, and time-based statements of future outcomes that the district will use to achieve each management goal in paragraph (1) of this subsection. Each future outcome must be the result of actions that can be taken by the district during the five years following the effective date of the adopted management plan;

(3) Performance standard(s) for each management objective. Performance standards are indicators or measures used to evaluate the effectiveness and efficiency of district activities. Evaluation of the effectiveness of district activities measures the performance of the district. Evaluation of the efficiency of district activities measures how well district resources are used to produce an output, such as the amount of resources devoted for each management action;

(4) Details of how the district will manage groundwater supplies in the district, including a methodology by which the district will track its progress in achieving its management goals. At least one goal must be tracked on an annual basis; however, other goals may be defined and tracked over a longer time period as appropriate;

(5) The actions, procedures, performance, and avoidance that are or may be necessary by the district to effect the plan, including specifications and proposed rules;

(6) Estimates of the following:

(A) modeled available groundwater in the district as provided by the executive administrator based on the desired future condition established under Texas Water Code §36.108;

(B) the amount of groundwater being used within the district on an annual basis taken from either the water use survey data provided by the executive administrator or the district's own estimate;

(C) the annual amount of recharge from precipitation, if any, to each aquifer within the district, as provided by the executive administrator;

(D) the annual volume of water that discharges from each aquifer within the district to springs and any surface water bodies, including lakes, streams, and rivers, as provided by the executive administrator;

(E) the annual volume of flow into and out of the district within each aquifer and between aquifers in the district, as provided by the executive administrator;

(F) the projected surface water supply in the district according to the most recently adopted state water plan; and

(G) the projected water demand for water in the district according to the most recently adopted state water plan; and

(7) Details of the district's consideration of:

(A) Water supply needs within the district according to the most recently adopted state water plan, emphasizing those needs that impact groundwater supply within the district; and

(B) Water management strategies sourced from within the district boundaries according to the most recently adopted state water plan, emphasizing strategies that are or will be impacted by district actions.

(b) The management goals, management objectives, and performance standards required in subsection (a)(1), (2), and (3) of this section must be consistent with the established desired future conditions of the district's groundwater management area(s).

(c) Estimates required in subsection (a)(5) of this section must be developed with groundwater availability modeling information provided by the executive administrator in conjunction with the district's best available site-specific information and data.

§356.53. Plan Submission.

(a) A district requesting approval of its management plan, or of an amended management plan to incorporate adopted desired future conditions, or any other updates as necessary, will submit to the executive administrator the following:

(1) one electronic copy of the adopted management plan; and

(2) documentation that the plan was adopted after notice posted in accordance with Texas Government Code Chapter 551, including a copy of the posted agenda, meeting minutes, and copies of the notice either posted on the district's website or provided to the county clerk.

(b) The plan or revised plan under §356.54 of this subchapter (relating to Approval) will be considered properly submitted to the executive administrator when all of the items specified in subsection (a) of this section are received by the executive administrator.

§356.54. Approval.

(a) The executive administrator will approve a plan as administratively complete when it contains the information required by Texas Water Code §36.1071(a) and (e). The executive administrator will notify the district in writing of the determination.

(b) If approval is denied, the executive administrator will provide written reasons for the denial with the notice of denial. A district has 180 days from receipt of notice to submit a revised management plan for review and approval. A revised [or amended] management plan must comply with all requirements of this subchapter.

(c) An approved management plan remains in effect until:

(1) the district fails to readopt a management plan at least 90 days before the plan expires;

(2) the district fails to submit the district's readopted management plan to the executive administrator at least 60 days before the plan expires; or

(3) the executive administrator determines that the readopted management plan does not meet the requirements for approval and the district has exhausted all appeals to the board or court in accordance with Texas Water Code §36.1072(f).

§356.55. Appeal of Denial of Management Plan Approval.

(a) If the executive administrator denies approval of a management plan, a revised management plan, or an amendment to a management plan, the district may appeal the denial by notifying the executive administrator in writing of its intent to appeal, not later than 60 days after the executive administrator's written notice of denial.

(1) Not later than 30 days after filing its notice of intent to appeal, a district will submit to the executive administrator in writing points of appeal addressing each of the executive administrator's reasons for denial of approval.

(2) The appeal must be heard at the first regularly scheduled meeting of the board to occur after the expiration of 30 days from the receipt of the district's written points of appeal. Written notice of appeal and written points of appeal will be considered to be received by the executive administrator when received in the Austin offices of the agency.

(3) The executive administrator may file a written response to the district's points of appeal with the board and must provide a copy of the response to the district.

(b) If the board upholds the executive administrator's decision to deny approval of the management plan, the district may request that the matter be mediated or, failing mediation, may appeal to a district court in Travis County, in accordance with Texas Water Code §36.1072(f).

§356.56. Approval of Management Plan Amendments.

(a) Amendments to a plan that substantially affect the management plan require approval by the executive administrator and must be submitted in accordance with §356.53 of this subchapter (relating to Plan Submission). Substantial amendments include updating estimates of modeled available groundwater, revising the desired future conditions goal, or any changes to elements required by Texas Water Code §36.1071. A plan must be updated no later than two years after the adoption of desired future conditions by the district representatives within the groundwater management area(s).

(b) If the district proposes to amend its plan for revisions of items not required by Texas Water Code §36.1071 or that do not substantially affect the plan, the district must submit a written copy of the proposed amendment to the executive administrator so that the executive administrator may determine whether the amendment requires approval.

(c) If the executive administrator determines that a proposed amendment substantially affects the plan and requires approval, the district must submit all amendments to the management plan developed under §356.52 of this subchapter (relating to Required Content of Management Plan) to the executive administrator within 60 days of adoption of the amendment by the district's board.

(d) All management plan amendments or proposed amendments must be submitted in writing to the executive administrator and include a cover letter noting the amendments made or proposed amendments to the plan.

§356.57. Sharing with Regional Water Planning Groups.

Each district must forward a copy of its approved management plan to the chair of each regional water planning group within the district's boundaries.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER G. BRACKISH GROUNDWATER PRODUCTION ZONES

31 TAC §§356.70 - 356.72

STATUTORY AUTHORITY (Texas Government Code §2001.033(a)(2))

The amendments are adopted under the authority of Texas Water Code §6.101, which provides the TWDB with the authority to adopt rules necessary to carry out the powers and duties in the Water Code and other laws of the State, and also under the authority of Water Code §§15.001, §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085.

This rulemaking affects Texas Water Code, §15.001 §16.0012, §16.060, §35.004, §36.001, §36.1015, §36.1071, §36.1072, §36.1073, §36.108, §36.1084, §36.1085, and §36.3011.

§356.70. Brackish Groundwater Production Zone Designation.

(a) The agency will identify and designate local or regional brackish groundwater production zones in areas of the state with moderate to high availability and productivity of brackish groundwater that can be used to reduce the use of fresh groundwater and that:

(1) are separated by hydrogeologic barriers sufficient to prevent significant impacts to water availability or water quality in any area of the same or other aquifers, subdivisions of aquifers, or geologic strata that have an average total dissolved solids level of 1,000 milligrams per liter or less at the time of designation of the zones; and

(2) are not located in:

(A) an area of the Edwards Aquifer subject to the jurisdiction of the Edwards Aquifer Authority;

(B) the boundaries of the:

(i) Barton Springs-Edwards Aquifer Conservation District;

(ii) Harris-Galveston Subsidence District; or

(iii) Fort Bend Subsidence District;

(C) an aquifer, subdivision of an aquifer, or geologic stratum that:

(i) has an average total dissolved solids level of more than 1,000 milligrams per liter; and

(ii) is serving as a significant source of water supply for municipal, domestic, or agricultural purposes at the time of designation of the zones; or

(D) an area of a geologic stratum that is designated or used for wastewater injection through the use of injection wells or disposal wells permitted under Texas Water Code Chapter 27.

(b) In designating a brackish groundwater production zone under this section, the agency will:

(1) determine the amount of brackish groundwater that the zone is capable of producing over a 30-year period and a 50-year period without causing a significant impact to water availability or water quality as described by subsection (a)(1) of this section;

(2) include in the designation description:

(A) the amounts of brackish groundwater that the zone is capable of producing during the periods described by paragraph (1) of this subsection; and

(B) recommendations regarding reasonable monitoring to observe the effects of brackish groundwater production within the zone; and

(3) work with districts and stakeholders and consider the most recently updated Brackish Groundwater Manual for Texas Regional Water Planning Groups and other relevant scientific data or findings.

(c) Areas of the state that are not designated as brackish groundwater production zones are not precluded from development of brackish groundwater or from future designation of zones.

(d) The agency may amend a designated brackish groundwater production zone upon its own initiative or upon request by a district. A request for an amendment from a district must be made in writing and include justification and documentation supporting the requested amendment.

(e) The Agency will provide notice of the intent to amend a designated brackish groundwater production zone with proposed changes to any district within the applicable brackish groundwater production zone and to the district(s) and any entity that requested the amendment through a district.

§356.71. Brackish Groundwater Production Zone Operating Permit Review.

(a) This section does not apply to a district that overlies the Dockum Aquifer and includes wholly or partly 10 or more counties.

(b) When a district submits an application for a brackish groundwater production zone operating permit to the agency, the agency will conduct a technical review of the application, subject to subsections (c) and (d) of this section.

(c) Upon receipt of such an application, the agency will assess the application to determine whether a proposed production well is located within a designated brackish groundwater production zone. If a proposed production well is not located within a designated brackish groundwater production zone, the agency will not conduct the technical review of the application. If a proposed production well is located within a designated brackish groundwater production zone, the agency will conduct the technical review of the applicable permit application or applicable portions of a permit application in accordance with subsections (d) - (f) of this section.

(d) Upon receipt of an application for a brackish groundwater production zone operating permit for a proposed production well located within a designated brackish groundwater production zone and that includes all of the information required by Texas Water Code §36.1015(g), the agency will conduct a technical review of the application. If the agency does not receive all of the information required by Texas Water Code §36.1015(g), the agency will notify the district of the missing information. The agency will not conduct a technical review of an incomplete application until all required information is received.

(e) After conducting the application assessment and required technical review of a complete application, the agency will provide a report of the technical review of the application to the district that submitted the application that includes:

(1) findings regarding the compatibility of the proposed well field design with the designated brackish groundwater production zone, including:

(A) whether the proposed production exceeds the amount of brackish groundwater that the zone is capable of producing over a 30-year period and a 50-year period, as determined pursuant to Texas Water Code §16.060(e) and in addition to the amount of modeled available groundwater provided under Texas Water Code §36.108; and

(B) whether the parameters and assumptions used in the model described in Texas Water Code §36.1015(g)(4)(A) are compatible with the designated brackish groundwater production zone;

(2) recommendations(B);

(3) verification the district rules require monitoring of land elevations for a project located in a designated brackish groundwater production zone in the Gulf Coast Aquifer, as required by Texas Water Code §36.1015(e)(5).

(f) The findings and recommendations included in subsection (e) of this section only be site-specific if the agency has received site-specific data and information from the district.

§356.72. Annual Report Review.

(a) When a district has received an annual report required under Texas Water Code §36.1015(e)(6) and reviewed the report for any missing information, the district will submit the report to the agency and request a review, under Texas Water Code §36.1015(j). The agency will investigate and issue a technical report to the district that sent the request, subject to subsection

(b) of this section.

(b) Upon receipt of a request, the agency will determine whether it has received the applicable annual report and all of the information required under Texas Water Code §36.1015(e)(6), and for a project located in a designated brackish groundwater production zone in the Gulf Coast Aquifer, the information required to be collected under Texas Water Code §36.1015(e)(5) related to subsidence. If the agency has not received all of the information required under Texas Water Code §36.1015(e)(6) or §36.1016(e)(5), as applicable, the agency will notify the district of the missing information and will not conduct a technical review of the reports until all required information is received.

(c) Not later than the 120th day after the date the agency receives all of the required information, the agency will investigate and issue a technical report on whether:

(1) brackish groundwater production from the designated brackish groundwater production zone under the project that is the subject of the report is projected to cause:

(A) significant aquifer level declines in the same or an adjacent aquifer, subdivision of an aquifer, or geologic stratum that were not anticipated by the agency in the designation of the zone;

(B) negative effects on quality of water in an aquifer, subdivision of an aquifer, or geologic stratum; or

(C) for a project located in a designated brackish groundwater production zone in the Gulf Coast Aquifer, subsidence during the permit term; or

(2) enough information is available to determine if brackish groundwater production from the designated brackish groundwater production zone under the project that is the subject of the report is projected to cause the conditions listed in paragraph 1 of this subsection.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Ashley Harden
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Texas Water Development Board
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TITLE 43. TRANSPORTATION

PART 1. TEXAS DEPARTMENT OF TRANSPORTATION

CHAPTER 9. CONTRACT AND GRANT MANAGEMENT

The Texas Department of Transportation (department) adopts the amendments to §§9.2, 9.15, 9.17, 9.23, and 9.24, relating to Contracts and Grant Management. The amendments to §§9.2, 9.15, 9.17, 9.23, and 9.24 are adopted without changes to the proposed text as published in the October 11, 2024, issue of the *Texas Register* (49 TexReg 8364) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENTS

The purpose of this rulemaking is to clarify the rules of the Texas Transportation Commission (commission) concerning the requirements for submitting certain claims for contracts entered into and administered by the Texas Department of Transportation (department).

Amendments to §9.2, Contract Claim Procedure, in subsection (g)(2)(B), prohibit the use of any type of total cost method when making a claim for additional compensation. This prohibition ensures that claims for additional compensation are based on verifiable direct costs attributable to specific changes and impacts. Additional amendments allow the committee chair to waive the meeting requirement if the department does not dispute the contractor's claim because such a meeting is unnecessary and to specify that rescheduling of meetings is at the committee chair's discretion, which will prevent unnecessary delay. The term "chairman" is also replaced with "chair" to align with the language used in 43 TAC §1.1, Texas Transportation Commission. The amendments also correct the reference in subsection (a)(1)(C) to the title of Transportation Code, Chapter 223.

Amendments to §9.15, Acceptance of Bids, clarify in subsection (e) that the department evaluates only the apparent low bid to determine whether the bid is unbalanced and provide that the department may determine that the apparent low bid is nonresponsive if the evaluation shows that the apparent low bid is both mathematically and materially unbalanced. This change provides for efficiency in the selection of bids for awarding contracts.

Amendments to §9.17, Award of Contract, delete the requirement of subsection (a)(2) that the commission reject all bids for a project if the lowest bid is determined to be both mathematically and materially unbalanced. This requirement is unnecessary because under language added to §9.15, a determination that a low bid is mathematically and materially unbalanced may result in the bid being considered nonresponsive.

Amendments to §9.23, Evaluation and Monitoring of Contract Performance, clarify that an interim evaluation must be completed as needed and on each anniversary date of when work began under the contract, if the project extends for longer than one year. These changes will assist in clearing ambiguity that could potentially result in inconsistent application of this requirement.

Amendments to §9.24, Performance Review Committee and Actions, replace the term "chairman" with "chair" to align with the language used in 43 TAC §1.1, Texas Transportation Commission.

COMMENTS

The department received comments from the Associated General Contractors of Texas (AGC) regarding the proposed amendments to §§9.15 and 9.17. The AGC stated their support for determining an apparent low bid nonresponsive if it is both mathematically and materially unbalanced and proceeding to the next lowest responsive bidder, but they expressed four points of concern.

Comment: Clarity is needed regarding whether a tertiary, and further down, bidders are eligible to receive an award when both the lowest and the second lowest bidder, etc., submits an unbalanced bid.

Response: Yes, the lowest responsive bid can be considered for award regardless of how many nonresponsive bids are received. However, the lowest responsive bid will be evaluated for award but may ultimately be rejected for the causes remaining in §9.17 or in the best interest of the State.

Comment: Allowing a bidder to rebid the project if the department decides to not award to the subsequent low bidder will remove inhibitions for mathematically and materially unbalancing bids, as there will be no risk to said bidder.

Response: If a bidder unbalances its bid, it risks its bid being determined nonresponsive and removed from consideration. While the department does not plan to restrict contractors from bidding if the project is relet, there remains another risk to deter bidders from unbalancing bids: if the department rejects all bids on the project, bidders removed for unbalancing will be tracked, and if the department has rejected two projects due to the bidder's error within a 36-month period, the bidder will be referred to the Performance Review Committee for consideration of remedial action under existing language in §9.24.

Comment: In cases where a quantity error was documented during the pre-bid Q&A process, the error was not corrected by addendum, and the low bidder is determined to be mathematically and materially unbalanced, the low bidder should not be subject to mathematically and materially unbalanced decisions, and rejection of all bids should be based on "an error in the plans."

Response: The department anticipates that in the majority of cases described, the original low bidder would be determined nonresponsive, and the new apparent low bidder would be awarded, assuming it met all requirements. If not, and the quantity error was materially significant, the department would consider the presence of a pre-bid question indicating the error, and it is likely that all bids would instead be rejected in the best interest of the state.

Comment: In any of these responsiveness or award decisions, the rules should include an allowance of time for due process for a bidder to present their case. This will require deferral by the Texas Transportation Commission, at least one month.

Response: This is addressed by existing language in §9.7 relating to protest of contract practices or procedures. The department notifies the bidder when its bid is determined nonresponsive and the reason for the determination. The bidder then has six days to submit a written protest to the department's executive director. Depending on the date of the determination, the department may recommend deferring the award decision to the following month.

SUBCHAPTER A. GENERAL

43 TAC §9.2

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission (commission) with the authority to establish rules for the conduct of the work of the department, and more specifically, Transportation Code, §201.112, which allows the commission by rule to establish procedures for the informal resolution of a claim arising out of a contract under the statutes set forth in that section, and Transportation Code, §223.004, which authorizes the commission to adopt rules to prescribe conditions under which a bid may be rejected by the department.

CROSS REFERENCE TO STATUTES IMPLEMENTED BY THIS RULEMAKING

Transportation Code, §§22.018 and 391.091, and Chapter 223 and Government Code, Chapter 2254, Subchapters A and B.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Becky Blewett
Deputy General Counsel
Texas Department of Transportation
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For further information, please call: (512) 463-3164

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SUBCHAPTER B. CONTRACTS FOR HIGHWAY PROJECTS

43 TAC §§9.15, 9.17, 9.23, 9.24

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission (commission) with the authority to establish rules for the conduct of the work of the department, and more specifically, Transportation Code, §201.112, which allows the commission by rule to establish procedures for the informal resolution of a claim arising out of a contract under the statutes set forth in that section, and Transportation Code, §223.004, which authorizes the commission to adopt rules to prescribe conditions under which a bid may be rejected by the department.

CROSS REFERENCE TO STATUTES IMPLEMENTED BY THIS RULEMAKING

Transportation Code, §§22.018 and 391.091, and Chapter 223 and Government Code, Chapter 2254, Subchapters A and B.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER I. DESIGN-BUILD CONTRACTS

43 TAC §9.152, §9.153

The Texas Department of Transportation (department) adopts amendments to §9.152 and §9.153 concerning Design Build Contracts. The amendments to §9.152 and §9.153 are adopted without changes to the proposed text as published in the October 11, 2024 issue of the *Texas Register* (49 TexReg 8370) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENTS

House Bill 2830, 86th Legislature, 2019, amended Transportation Code, Chapter 223, Subchapter F, which authorizes the department to enter into a design-build contract for a highway project, and prescribes the procurement process to be followed by the department for a design-build contract.

House Bill 2830 revised the limitation on the number of design-build contracts that may be entered into by the department to no more than six contracts each fiscal biennium, and amended Transportation Code, §223.246(a), to require a request for proposals for a design-build project to include a design, rather than a schematic design, that is approximately 30 percent complete.

Amendments to §9.152, General Rules for Design-Build Contracts, clarify that the department's reserved rights in administering a procurement for a design-build project includes the right to suspend the procurement. Because of project delays or for other reasons, the department may need to suspend the procurement for a design-build project.

Transportation Code, §223.246(a)(5), previously required a request for proposals to include a schematic design that is approximately 30 percent complete. In general, a schematic design that is 100% complete is comparable to a design that is approximately 30 percent complete.

Amendments to §9.153, Solicitation of Proposals, implement the changes made by House Bill 2830 by providing that a request for proposals must include a design that is approximately 30 percent complete. This change provides the department with the flexibility to develop a project with enough detail to aid the procurement process, cost estimation, and understanding of contractor and department risk.

Transportation Code, §223.249, provides that in a request for proposals, the department shall provide for the payment of a partial stipend in the event that a procurement is terminated before the execution of a design-build contract. As the Texas Constitution generally prohibits grants of public funds, payment of stipends to proposers without receiving work product in exchange would raise constitutional issues. The amendments to §9.153(f) clarify that, if a procurement is terminated, a partial payment will be paid to an unsuccessful proposer that submits a proposal responsive to the requirements of the request for proposals. The partial payment would be made in exchange for the work product in the proposal. The amendments allow the department to request that a proposer submit to the department work product that was developed by the proposer for a project if the procurement for the project is terminated before receipt of proposals. A partial payment for that work product may be made if the department determines that the requested work product was developed in accordance with the requirements of the request for proposals and can be used by the department in the performance of its functions. In all cases, the amount of the payment to a proposer will not exceed the value of the work product to the department, as determined by the department.

COMMENTS

No comments on the proposed amendments were received.

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission (commission) with the authority to establish rules for the conduct of the work of the department.

CROSS REFERENCE TO STATUTES IMPLEMENTED BY THIS RULEMAKING

Transportation Code, Chapter 223, Subchapter F.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 13. MATERIALS QUALITY
SUBCHAPTER A. GENERAL

43 TAC §13.8

The Texas Department of Transportation (department) adopts the repeal of §13.8, relating to Testing Asphalt. The repeal of §13.8 is adopted without changes to the proposed text as published in the October 11, 2024, issue of the *Texas Register* (49 TexReg 8375) and will not be republished.

EXPLANATION OF ADOPTED REPEAL

During the periodic rule review, the department determined that the procedure set out in §13.8 is obsolete. The rule was adopted in 1991 to encourage asphalt binder suppliers to provide products that consistently comply with the department's specifications. Over the years, the department's Asphalt Binder Quality Program has been continually strengthened to ensure that the quality of asphalt binder products used on the department's projects meets the department's specifications. The program preemptively ensures consistency by requiring suppliers to share their data and updates with the department, enforces compliance through suspension or disqualifications, and ensures transparency. This approach more effectively encourages suppliers to comply with department's specifications than the approach provided by §13.8.

Section §13.8, Testing Asphalt, is repealed.

COMMENTS

No comments on the proposed repeal were received.

STATUTORY AUTHORITY

The repeal is adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission (commission) with the authority to establish rules for the conduct of the work of the department.

CROSS REFERENCE TO STATUTES IMPLEMENTED BY THIS RULEMAKING

N/A

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 21. RIGHT OF WAY
SUBCHAPTER B. UTILITY ADJUSTMENT, RELOCATION, OR REMOVAL
43 TAC §21.25

The Texas Department of Transportation (department) adopts the amendments to §21.25 concerning State Participation in the Relocation of Certain Publicly-Owned Utility Facilities. The amendments to §21.25 are adopted without changes to the proposed text as published in the October 11, 2024, issue of the *Texas Register* (49 TexReg 8376) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENT

S.B. 2601, Texas Legislature, 88th Regular Session, 2023, amended Transportation Code, §203.092(a-4), to add water supply or sewer service corporations organized and operating under Water Code, Chapter 67, to the entities that are authorized to apply for financial assistance for the relocation of utility facilities if the relocation is required for improvements of the highway system.

Amendments to §21.25, State Participation in the Relocation of Certain Publicly-Owned Utility Facilities, add language to allow a water supply or sewer service corporation organized and operating under Water Code, Chapter 67, to qualify for the department's program for reimbursing certain costs of the relocation of utility facilities required for a state highway project.

COMMENTS

No comments on the proposed amendment were received.

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission (commission) with the authority to establish rules for the conduct of the work of the department, and more specifically, Transportation Code, §203.095, which requires the commission to adopt rules relating the relocation of utility facilities.

The authority for the adopted amendments was provided by S.B. 2601, 88th Regular Session, 2023. The primary author and the primary sponsor of that bill are Sen. Juan Hinojosa and Rep. Terry Canales, respectively.

CROSS REFERENCE TO STATUTES IMPLEMENTED BY THIS RULEMAKING

Transportation Code, §203.092.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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