TITLE 16. ECONOMIC REGULATION

PART 1. RAILROAD COMMISSION OF TEXAS

CHAPTER 3. OIL AND GAS DIVISION

16 TAC §3.9, §3.46

The Railroad Commission of Texas (Commission) adopts amendments to §3.9 and §3.46, relating to Disposal Wells, and Fluid Injection into Productive Reservoirs, with changes to the proposed text as published in the August 29, 2014, issue of the *Texas Register* (39 TexReg 6775). The adopted amendments incorporate requirements related to seismic events in connection with disposal well permits, monitoring and reporting.

SUMMARY OF CHANGES FROM THE PROPOSAL LANGUAGE

As proposed, the Commission would have required that applicants for disposal well permits provide with the application the results of a calculation of the estimated five pounds per square inch (psi), 10-year pressure front boundary and use that area to determine whether or not there has been historic seismic activity. In response to comments, the Commission agrees that, in many instances, the assumptions and approximations used by applicants in such calculations would be highly interpretive and difficult for many operators to obtain, particularly for applicants proposing to dispose into non-productive formations. As a result, the results from such calculations could be non-uniform and misleading. Therefore, the Commission is adopting a simpler and more consistent method of determining the area to be surveyed. The Commission is now requiring that an applicant for a disposal well permit include with the permit application a printed copy or screenshot showing the results of a survey review of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location. The language regarding calculation of a pressure front boundary around a proposed disposal well location has been moved to §3.9(3)(C) and §3.46(b)(1)(D) and such calculation will be required only in certain limited circumstances where additional information is necessary to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval.

Also in response to comments, the Commission has revised the proposed language in §3.9(6)(A)(vi) and §3.46(d)(1)(F) relating to modification, suspension, and termination of a permit to replace the phrase "if injection is suspected of or shown to be causing seismic activity" with the phrase "if injection is likely to be or determined to be causing seismic activity."

The Commission adopts a minor clarifying change in §3.9(11)(A) and (B), and §3.46(i).

COMMENTS

The Commission received 36 comments on the proposed amendments. The Commission appreciates the interest shown by the public in this rulemaking effort. The Commission received timely-filed comments from 20 entities, 10 of which were from groups or associations: Environmental Defense Fund ("EDF"); Neighborhoods of East Fort Worth; Sierra Club, Lone Star Chapter ("Sierra Club"); Texas Alliance of Energy Producers (the "Alliance"); Texas Energy Services Coalition; and a workgroup comprised of the following associations: Texas Oil and Gas Association, the Texas Independent Producers & Royalty Owners Association; the Texas Alliance of Energy Producers, the Permian Basin Petroleum Association, and the Association of Energy Service Companies (the "Workgroup"). The Commission received comments from four groundwater conservation districts (collectively, the "GCDs"): Lone Star Groundwater Conservation District ("Lone Star GCD"); North Texas Groundwater Conservation District ("North Texas GCD"); Prairielands Groundwater Conservation District ("Prairielands GCD"); and Upper Trinity Groundwater Conservation District ("Upper Trinity GCD"). The Commission received timely-filed comments from three other governmental entities: United States Environmental Protection Agency ("EPA"); the City of Southlake; and the United States Geological Survey ("USGS"). The Commission received timely-filed comments from three companies: Chevron USA Inc. ("Chevron"); CrownQuest Operating, LLC ("CrownQuest");

and Pioneer Natural Resources ("Pioneer"). The Commission received 23 comments from individuals. After the September 29, 2014, comment deadline, the Commission received late-filed comments from two companies (Apache Corporation and Newfield Exploration Company ("Apache/Newfield")) and one governmental entity (Frio County Commissioners Court).

Four commenters expressed support for the proposed rule amendments. Neighborhoods of East Fort Worth provided a resolution in support of the proposed amendments. One commenter expressed support for the provisions for §3.9(6) to permit the Commission to respond to an appearance of seismic activity without conclusive evidence that the activity is triggered or induced by a particular well. This commenter also expressed support for the proposed amendments in §3.9(11) to allow the Commission to require closer monitoring and reporting of injection pressure and rate. The Commission appreciates these comments. The Commission made no change in response to these comments.

Three commenters expressed opposition to hydraulic fracturing in Texas. One expressed opposition to fossil fuels. Another commenter expressed support for limiting hydraulic fracturing. These comments are beyond the scope of this rulemaking. The Commission made no change in response to these comments.

One commenter stated that the proposed amendments lack a methodology to catalogue quakes and relate them in proximity to existing wells, and that the proposal does not require operators to report quake events in proximity to their wells.

The Commission notes that seismic activity is reported by the USGS and that Commission staff is monitoring seismic activity in the state in relation to proximity to existing wells. The Commission made no change in response to this comment.

Two commenters expressed concern with individual property rights, seismic activity associated with hydraulic fracturing, and decreased property values. These commenters recommended that the Commission amend the rules to provide further protection for property owners in areas in which drilling is to occur. One commenter stated that the commenter's home has been damaged by the earthquakes in the Azle/Reno area and recommended stronger laws and rules and permits governing the gas industry. One commenter recommended that the Commission require operators to buy earthquake insurance.

A review of the numerous studies of seismic activity in areas with oil and/or gas exploration and production indicates that seismic activity induced by hydraulic fracturing is not very likely. In addition, the Commission has no statutory authority to require an operator to purchase insurance. The Commission made no change in response to these comments.

USGS commented that the Commission was incorrect in stating that the USGS has the ability to detect and locate all seismic events larger than magnitude 2.0 throughout the continental United States. USGS went on to state that it is currently capable of detecting and locating all Texas earthquakes with magnitudes of about 3.0 and larger and can detect smaller earthquakes in regions with better seismic station coverage. The Commission acknowledges the correction, but no change to the rules is necessary.

Two commenters noted that USGS earthquake locations in Texas are not sufficiently accurate to retrieve data regarding the locations of historical seismic events within an the estimated 10-year, five psi pressure front boundary.

The Commission agrees with the statement concerning USGS earthquake location accuracy; the Commission is simply using the reported earthquake locations as a screening tool for disposal well applications. However, the Commission finds that it is appropriate to require permit applicants to access the USGS database and adopts a change to require a circular survey area of 100 square miles centered on the proposed disposal well location.

Five seismologists (Brian Stump, Heather DeShon, Matthew J. Hornbach, Maria Beatrice Magnini, and Christopher T. Hayward) (Stump et al.) jointly filed comments concerning the proposed fluid calculations, concluding that pressure front predictions will likely be subject to large uncertainties in predicting where the pressure front is located as a function of time.

The Commission agrees with the comments concerning the proposed fluid calculations, concluding that pressure front predictions will likely be subject to large uncertainties in predicting where the pressure front is located as a function of time. The Commission adopts a change to require that applicants for a disposal well permit review a defined survey area, and has moved the language regarding pressure front boundaries to the list of additional information that may be required of an applicant subsequent to a determination of the existence of complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the survey area.

Stump et al. questioned the motivation for choosing a five psi pressure front over 10 years, as the critical pressure number or time and recommended that the Commission require that an applicant for a disposal well permit avoid any pressure development near a major fault system that is active or appears critically stressed.

The Commission proposed five psi as a pressure differential on the lower side of the 1.4 to 14 psi range mentioned by the commenters as a conservative number. The Commission chose to compute the pressure front boundary after 10 years of operation at the proposed maximum daily disposal volume to represent an operational maximum value for fluid injected, because few operators operate disposal wells at the maximum daily allowed volume over extended periods of time, and large volume disposal wells are considered to have a lifespan of approximately 10 years. The Commission made no change in response to this comment.

Stump et al. recommended that the Commission consider situations where the reported pressures downhole are significantly in excess of five psi due to overpressure as industry studies already suggest that overpressures sometimes exist in some of the injection formations, and may exceed tens of psi.

The Commission agrees with the comment; however, no change is necessary for calculating the pressure front boundary as described because of the adopted changes. The Commission made no change in response to this comment.

Stump et al. noted that the "injected fluids may well stay confined in the injection interval but the pressure perturbation induced by the injections fluids can have farther reaching effects." These commenters further stated that the perturbation may be more important in locally changing stress in a manner sufficient to allow earthquakes along pre-existing fault structures. These commenters noted that there are a number of other critical data sets related to the fluids and the rock properties that control fluid migration, including, but not limited to downhole pressures in the injector, static pressures at injection depth, permeability and fault locations including their connection to layers above and below the injection interval. These commenters recommended that the Commission consider requiring annual measurement and reporting of bottom hole shut-in pressures to determine if injected fluids are having far-reaching effects on subsurface stress.

The Commission agrees with the comments, but disagrees that requiring industry to measure and report annually bottom hole shut-in pressures at all disposal wells is warranted. The language of the proposed rule would allow the Commission to add such a condition in reservoirs for which such monitoring and reporting might be warranted. The Commission made no change in response to this comment.

Stump et al. noted that many of the earthquake sequences in Texas, such as those in Azle, DFW and Cleburne, only began after the injectors began operating in the area, and that searching for earthquakes before the injection process begins may not be sufficient. These commenters further stated that any information on the locations of subsurface faults and their orientation relative to the in-situ stress field might provide more effective permitting criteria based on some of the historical earthquake data. These commenters pointed out that imaging and location of subsurface faults may be problematic. Even small offset faults at the limit of high-quality 3D seismic data may generate small magnitude earthquakes based on data analysis in Azle.

The Commission disagrees that these changes are necessary. Because the recurrence rate for these types of sequences is unknown, one cannot with any confidence correlate the onset of an earthquake sequence with any measureable impact of injection well operation. The Commission made no change in response to this comment.

Stump et al. noted that a characteristic radius for the search might be a better approach rather than one estimated from a model run because: (1) the earthquake locations based on regional observations have a characteristic error in latitude and longitude of approximately 10 kilometers which may be larger than estimated radius; (2) few details are described in models and an assessment of the errors in the calculation may necessitate a larger radius (e.g., the bottom hole pressures and permeability used can greatly influence the estimate radius); and (3) model runs can be influenced by inclusion of faults.

The Commission agrees that a characteristic radius will provide a more straightforward review of historical earthquake occurrence and adopts a circular survey area of 100 square miles centered on the proposed disposal well location in §3.9(3)(B) and §3.46(b)(1)(C).

Stump et al. noted that the "magnitude threshold for the USGS catalog should be checked with the USGS." Chevron pointed to the preamble reference to magnitude 2.0 events as the USGS framework of reference and stated that magnitude 2.5 is a more appropriate threshold for references to USGS given the current seismic monitoring network in Texas. Chevron commented that it is important that seismic monitoring be consistent in both space and time such that a threshold magnitude event can be detected no matter where it occurs in Texas and that an increase in detected threshold events over time as the monitoring network improves is not misinterpreted as an increase in seismic events. Chevron recommended that the Commission lower the threshold once an expanded seismic network is in place. Similarly, Pioneer recommended that the Commission revise the proposed rule language to include the following: "the results of a review of information from the USGS threshold of 2.5 magnitude on the Richter Scale." Pioneer stated that such language would provide clarity and certainty should specific seismic monitoring of a particular area use technology that would allow measurements to a lower threshold. One commenter stated that the preamble reference to magnitude 2.0 events as the USGS frame of reference is incorrect and suggested that magnitude 2.5 is more appropriate given the current monitoring capability.

One commenter stated that defining a numerical seismic magnitude threshold would provide precise clarity in the rule and prevent the need to readdress this issue in the future as technology changes in Texas or in other parts of the country.

Based on these comments submitted by the USGS, Stump et al., Chevron, Pioneer and two others, the Commission agrees with comments regarding the capability of the USGS monitoring in Texas. Nonetheless, the Commission retains the option to consider any earthquake reported on the USGS database. The suggested numerical seismic magnitude threshold would preclude including smaller earthquakes that might be reported in the future where denser monitoring could detect smaller earthquakes. Further, earthquakes with magnitudes well below magnitude 2.0 are being used to delineate basement seated faults in the Reno, Texas, area. The Commission made no change in response to these comments.

One commenter recommended that the Commission defer action on the requirements proposed for §3.9(3)(C) and §3.46(b)(1)(D) to require submission of additional information with permit applications because, given the current state of the science, the information proposed to be requested of an applicant would not allow the Commission to predict seismic activity and "science is not yet ready to inform the correct rules." This commenter recommended that the Commission determine whether the changes in the proposed amendments can be applied to past situations to gather proposed information, and determine that it would have been of some predictive value and applied to a variety of likely situations to verify that reliable and consistent collection and reporting is feasible and practical. This commenter also recommended that the Commission measure the actual cost of compliance. Apache/Newfield also expressed concern that the apparent simplicity of a statewide, one-size-fits-all regulation may not be in the best interest of the state or the public, because the natural geologic and land-use variability that occurs across Texas results in different risk profiles. Consequently, Apache/Newfield recommended that the Commission consider requiring different actions in different areas of the state based on seismic risk. Chevron echoed that comment by stating that, because seismicity that appears to be associated with disposal wells in Texas is concentrated in a limited number of localities, seismicity would be better addressed through field rules. Chevron stated that addressing seismicity in statewide rules that need only apply in a few areas would be detrimental to resource development.

The Commission agrees with the commenters that the science is not exact and more study of natural and induced seismic events is needed. However, the Commission has amended the rules based on the best information from current science. These rule amendments address disposal wells located in new areas, or more or higher volume disposal wells located in areas with existing oil and gas activity. In addition, the rule language is sufficiently broad to allow the Commission to require information based on advancing science. The Commission made no change in response to this comment.

The Alliance recommended that the Commission consider the basic roles of injection pressure, depth of injection, and volume of injected fluid, which play a significant role in injection permitting. Lower injection pressure generally results in lower volumes of fluids being disposed. These lower volume, lower pressure wells will consistently have a smaller zone of influence on subsurface pore pressure over time. This smaller zone of influence means less risk of induced seismicity. Therefore, the Alliance recommended that the Commission revise the rule to exempt disposal wells with an injection volume of 5,000 barrels per day or less, unless the well falls within 20 circular square miles (2.5 mile radius) of the radius survey area of an historic seismic event of a magnitude of 2.5 or higher. The Alliance recommended for higher volume wells (greater than 5,000 barrels per day) a survey area of 40 circular square miles (approximate four-mile radius).

The Commission agrees that injection pressure, depth of injection, and volume of injected fluid play a significant role in injection permitting. However, the survey area addressed in this rulemaking is intended to address increased pressure that could trigger movement of existing stressed faults. No one knows where all faults are, whether they are under stress, or how much of an increased reservoir pressure would trigger movement of an existing stressed fault. In addition, the increased impact of several "small volume" disposal wells in one area could have the same impact as one "large volume" disposal well. However, as previously discussed, the Commission adopts a more appropriate method for surveying the area surrounding the location of a proposed disposal well, requiring the applicant to survey a reasonably conservative area around the proposed disposal well location for historic seismic activity as indicated by USGS. The Commission has determined that a reasonably conservative area for such a survey is a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location. Such review places minimal burden on an applicant. The Commission made no change in response to the request for a survey area based on volume.

One commenter recommended that the Commission combine the proposed changes in §3.9(3)(C) and (D) and §3.46 (b)(1)(C) and (D) so that all requirements are included in one amendment. This commenter expressed concern that earthquakes can occur in areas without historic seismic activity. Just because an area has had no prior earthquake activity does not mean that it will not occur when a well is put into operation. This commenter also recommended that the Commission revise the proposed language in §3.9(3)(C) and (D) and §3.46(b)(1)(C) and (D) to substitute the word "will" for the word "may."

The Commission selected the word "may" to indicate that the Commission may require the applicant to provide some or all of the additional information. Commission staff will review the particular well and well location to determine what additional information may be needed. The Commission disagrees that it must require all of the information in every case. The Commission made no change in response to this comment.

One commenter expressed concern about the potential cost to applicants and stated that earthquakes from salt water disposal ("SWD") injection wells are not common to all areas and injection intervals. This commenter recommended that the Commission form a new unit (similar to the Commission's Groundwater Advisory Unit) to advise on the potential for historic earthquakes at the proposed disposal well location. This commenter stated that the cost of seismic lines for each new location is prohibitive and will increase the cost of disposal considerably, as well as result in time delays. The presence of nearby faults at the disposal well location also could be part of the Commission responsibility by subscribing to the GeoMap mapping service on a statewide basis.

The Commission disagrees with this comment. The Commission's Underground Injection Control regulations appropriately place the burden on the applicant to provide the Commission with the information to justify issuance of a permit. In addition, the rule amendments do not require the placement of seismic lines at every proposed disposal well location. The Commission made no change in response to this comment.

Apache/Newfield recommended that the Commission and the industry focus in the short-term on better understanding seismicity issues. This commenter recommended that the Commission undertake a thorough analysis of known cases where disposal by injection is believed to be coincident with seismicity. Rather than place the complete burden on one operator to perform the necessary technical work and possibly collect confidential business information from other operators, the commenter recommended that the Commission identify specific areas of interest across the state and request funding from the State Legislature for comprehensive integrated subsurface geological, geophysical, and fluid modeling studies by Texas institutions of higher learning, with input from industry, for the purpose of creating maps. This commenter recommended that the Commission consider rule amendments after these studies.

Although the Commission agrees that additional study is warranted, the Commission does not agree that this rulemaking effort should be postponed. The recommended studies would require vast amounts of funding and time. Meanwhile, Texas has experienced seismic activity over the past few years. The Commission made no change in response to this comment.

The Workgroup commended the Commission for being proactive in responding to seismic activity, including the hiring of a seismologist and proposing reasoned requirements to address the risk of seismic activity related to disposal well operations. The Workgroup found the following provisions acceptable: (1) using the USGS database as the source for historic seismic activity; (2) amending §3.9(6)(A)(vi) and §3.46(d)(1)(F) to include disposal that is shown to be causing seismic activity to the list of reasons for which the Commission may modify, suspend, or terminate a disposal well permit for just cause and after opportunity for hearing; (3) requiring operators to collect disposal volumes and pressures as requested by the Commission for submittal; and (4) requiring additional technical data such as logs and geologic cross-sections where conditions exist that may increase the risk that fluids will not be confined to the injection interval or being possibly connected to seismic events nearby. Chevron, Pioneer, and Apache/Newfield expressed support for the Workgroup comments. The Commission appreciates these comments.

The Workgroup commented, however, that, while pressure front calculations can be an appropriate part of a robust technical review and risk assessment where there have been seismic events in close proximity to a proposed new disposal well, the Workgroup questioned using five psi pressure front calculations as a tool simply to delineate an area for assessing historic seismic activity. The Workgroup expressed concern that the number of poorly constrained variables that go into such a calculation may lead to underestimating or overestimating the location of the pressure front boundary, thereby rendering a common and consistent review of historic seismic events in a given area unlikely. Further, the Workgroup stated that the methodology and results would not be transparent to all stakeholders, and would also place a substantial burden on small operators by requiring them to retain additional technical resources to perform calculations solely to obtain information on historic seismicity. The Workgroup and Chevron stated that a more transparent, repeatable and risk-appropriate approach would be to require a review of USGS historic seismic activity within a circular area of 40 square miles centered around the proposed location for large disposal wells. The Workgroup recommended that shallow, low volume disposal wells be exempted from this requirement or that the Commission require the use of a smaller area for referencing historic seismic events. The Texas Energy Services Coalition echoed these concerns, but recommended survey of a circular area of 20 square miles centered around the proposed disposal well location.

Chevron commented that the proposed rule does not state any guidelines for the input data or parameters, or calculation method(s) for determining the pressure front, making the rule somewhat ambiguous and problematic in its application. Without specific guidance regarding verification of the input parameters (some of which are rarely measured and can vary by orders of magnitude) and calculation method, the confidence level in the calculation would be low and the uncertainty high. This commenter stated that the actual pressure front that would be induced in the subsurface would be complicated by the actual injection history, faults, injection horizon parameters, and interaction with other wells.

The Commission agrees that, in many instances, the assumptions and approximations used by applicants in such calculations would be highly interpretive and difficult for many operators to obtain, particularly for applicants proposing to dispose into non-productive formations. As a result, the results from such calculations could be non-uniform and misleading. Therefore, the Commission adopts a simpler and more consistent method of determining the area to be surveyed. The Commission will require that an applicant for a disposal well permit include with the permit application a printed copy or screenshot showing the results of a survey review of information from the USGS regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

The Workgroup recommended that the Commission move the language regarding pressure front calculations to §3.9 (3)(C) and §3.46(b)(1)(D) as part of the additional information that may be required by the Commission. Chevron commented that, if pressure front calculation requirement is retained, it should be placed in §3.9(3)(C) and §3.46(b) (1)(D), as data that may be required on a case-by-case basis. The Commission agrees with these comments and has made the recommended change.

One commenter stated that he had trouble using the USGS Earthquake Archive Search & URL Builder site. The Commission contacted this person to assist with navigating the USGS website. The Commission made no change in response to this comment.

The GCDs commended the Commission on proposal of the rule and, in general, expressed support for the proposed changes to the rules and the Commission's efforts to ensure fluids from disposal wells are confined to the injection interval and not at risk of migrating to freshwater resources. The Commission appreciates these comments.

The GCDs recommended that the Commission require disposal well applicants to include their calculations for determining pressure front boundary and area of influence for fluid migration in the disposal well application, so that the values they use as parameters for the equations and their calculations can be reviewed by Commission staff and third parties.

The Commission agrees in part with this comment. In cases where the Commission requires the performance of pressure front boundary calculations, the actual input parameters and calculations also would be required. The Commission made no change in response to this comment.

Upper Trinity GCD also suggests that the Commission amend the proposed language to require that all disposal well permit applicants provide the Commission with the additional information, such as logs, geologic cross-sections, and/or structural maps, to demonstrate fluid confinement to the injection interval, rather than leaving this as a permissive option for the Commission staff to review on a case-by-case basis. The GCD recommended that §3.9(3) (C) be changed so that the Commission will require each applicant to submit the information, rather than leaving it as optional. The GCD also noted that the term "baserock" should be "basement rock."

The Commission disagrees with the first recommended change. The existing requirements for disposal well permit applications are adequate to make such a determination in most instances. The Commission will require the additional information in §3.9(3)(C) to address instances in which additional information is necessary to make such a determination. The Commission agrees that the term "basement rock" is more correct than the term "baserock" originally proposed, and adopts the recommended change.

Pioneer requested clarification that the additional data that could be requested by the Commission under §3.9(3)(C) or §3.46(b)(1)(D) would be existing data.

Although existing data will be adequate in most cases, the possibility exists where sufficient information would not allow the Commission to adequately assess seismic threat. Therefore, if the applicant wishes to pursue a disposal well permit application in such circumstances, new data may be necessary. The Commission made no change in response to this comment.

Pioneer also requested clarification that in order to comply with the rule amendments, operators will not be responsible for purchasing and/or installing seismographs, geophones or other monitors designed to detect seismic activity.

The Commission did not propose the requirement for an operator to purchase and/or install seismographs, geophones, or other monitors designed to detect seismic activity. However, there could be an unusual case where an operator would elect to use this equipment. The Commission made no changes in response to this comment.

The GCDs recommended that the Commission consider providing additional definitional guidance through the proposed rules on what it will consider to constitute "complex geology" for the purposes of requiring additional information from permit applicants to demonstrate confinement of fluids.

The Commission declines to define "complex geology" in the rule because an all-inclusive definition is not possible. However, some examples might include heterogeneity, varying permeability and porosity, faulting and folding, high stress, unconformities, tilted or rotated fault blocks, and cross-stratification. The Commission made no change in response to this comment.

The GCDs requested that the Commission continue to take the necessary steps to protect not only freshwater resources, but brackish water as well, in the regulation of disposal wells and potential sources of contamination.

This comment is beyond the scope of this rulemaking. Texas Natural Resources Code, §91.101, relating to rules and orders, requires the Railroad Commission to adopt and enforce rules and orders and issue permits relating to "the production of oil and gas, including activities associated with the drilling of injection water source wells which penetrate the base of useable quality water." The Commission provides letters of recommendation concerning groundwater protection. For recommendations related to normal drilling operations, shot holes for seismic surveys, and cathodic protection wells, the Commission provides geologic interpretation identifying the base of usable-quality water (generally less than 3,000 milligrams per liter (mg/L) total dissolved solids (TDS), but may include higher levels of TDS if identified as currently being used or identified by the Texas Water Development Board (TWDB) as a source of water for desalination). The geological interpretation may include groundwater protection based on potential hydrological connectivity to usable quality water. For recommendations related to injection into a non-producing zone, the Commission provides geologic interpretation of the base of the underground sources of drinking water (USDW). USDW is defined as an aquifer or its portions which supplies drinking water for human consumption; or in which the groundwater contains fewer than 10,000 milligrams per liter TDS; and which is not an exempted aquifer. The Commission's UIC program prohibits injection into (unless the EPA has approved an aquifer exemption) or contamination of USDWs. The Commission's Groundwater Advisory Unit coordinates with the TWDB with respect to desalination projects and water use. The Commission also is a member of the Texas Groundwater Protection Committee. The Commission made no change in response to this comment.

The Lone Star GCD stated that §3.9 and §3.46 currently require an applicant for an injection well permit to review an area of a fixed radius of 1/4 mile for abandoned, unplugged, or improperly plugged wells that could serve as a conduit for migration of injectate to freshwater (area of review). The Lone Star GCD recommended that the Commission amend the rules to require that an applicant calculate a site-specific area of review for all injection wells.

The commenter appears to be confusing the "area of review" requirement in the rules and the area to be surveyed for historic seismicity. When the federal Underground Injection Control (UIC) regulations were promulgated in 1980 under the Safe Drinking Water Act (SDWA), they required that a review of wells within a 1/4 mile radius of the proposed injection well be conducted to ensure that surrounding wells would not serve as a conduit for injected fluids to enter USDWs. This requirement is known as the area-of-review or AOR requirement. Sections 3.9 and 3.46, adopted in 1981, require a 1/4 mile AOR unless an applicant shows by computation that a lesser area will be affected by pressure increases. The "area of review" with respect to the underground injection program is the area surrounding an injection well that is reviewed during the permitting process to determine if flow between aquifers will be induced by the injection operation. The area of review defines the area where the injection reservoir pressure under the influence of injection activity could cause fluid to move into a USDW. The area of review is determined based on the location at which fluids from the injection zone would rise in a hypothetical well at a given location. The Commission's UIC program was approved with a fixed radius of 1/4 mile. The information is used to determine whether corrective action is necessary.

In most cases, the Commission's AOR review involves a review of the map of wells within a 1/4 mile radius of the proposed injection or disposal well and the corresponding "Table of Wells" indicating the status of all wells within the 1/4 mile radius to verify that the operator has indicated that the wells are active, have an exception to §3.14 of this title (relating to Plugging), or are properly plugged. For applications in selected problem areas, the Commission's UIC staff performs the more detailed review. The more detailed AOR reviews are performed for applications for wells located in areas of highly pressured formations, highly corrosive formation waters, public concern over injection wells, or where unplugged abandoned wells are a real or perceived problem. The more detailed review involves pulling and reviewing all completion and plugging reports for all wells within the 1/4 mile radius to verify that the wells are properly completed and/or plugged. In addition, in certain areas, such as areas in which the reservoir pressure is elevated, the Commission has determined that a larger area of review is warranted.

The survey area in this rulemaking is intended to address increased pressure that could trigger movement of existing stressed faults. In any event, this comment is beyond the scope of the proposed rulemaking, which is limited to seismicity associated with disposal wells. The Commission made no change in response to this comment.

The EDF and the Sierra Club expressed general support for the proposed amendments. The Commission appreciates these comments. The Commission made no change in response to these comments.

The Sierra Club also recommended more research efforts and appropriate regulation to encourage operators to move away from underground injection to prevent contamination, and to provide a potential, available water resource for Texas.

The Commission agrees that produced fluids are a potential source of available water for Texas, but finds that this comment is beyond the scope of this rulemaking. The Commission encourages the re-use of these produced fluids when possible, particularly through the Commission's current rules relating to recycling of these fluids (in §3.8 of this title, relating to Water Protection, and in Chapter 4, Subchapter B, of this title, relating to Commercial Recycling.) However, current technology, as well as the storage and transportation costs, with respect to use of these fluids as a potential fresh water source is not yet economical in all instances. In addition, EPA estimates that there are 144,000 Class II injection wells in the United States, and the Commission has permitted over 50,000 Class II injection wells in Texas since the 1930s, with relatively few problems. The Commission made no changes in response to this comment.

The EDF encouraged the Commission to continue to study the issue and develop protocols for responding to future seismic events. The Sierra Club recommended that the Commission include in the rule: (1) a discussion of the types of information needed, including but not limited to a discussion of radioactive tracer or spinner surveys, well logs, and geological investigation of potential faulting; (2) a requirement for a seismic monitoring plan, such as pre- and post-monitoring of the region for earthquakes; (3) a requirement for monitoring before injection and testing and recording of original bottomhole injection interval pressure; and (4) a requirement for a shut-off device on the injection pump set to allow the maximum allowable injection pressure so that the Commission and operators can assure safe disposal. The Sierra Club also recommended that the Commission develop a seismic monitoring plan for assessing induced seismicity that may be or could be associated with existing permits.

Commission efforts to study issues related to seismic events are ongoing. Commission staff, including the Commission's seismologist, are participating in the Induced Seismicity by Injection Work Group of the State Oil and Gas Regulatory Exchange established by the Interstate Oil & Gas Compact Commission and the national Ground Water Protection Council, which includes representatives from state regulatory agencies and geological surveys across the country. State agencies participating in this work group are collaborating and sharing science, research, and practical experience to equip the states with the best decision making tools to evaluate the possible connections between seismic events and injection wells, minimize risk, and enhance appropriate readiness when seismic events occur. The State Oil and Gas Regulatory Exchange initiative is part of a larger state-led effort called States First, through which state oil and gas regulatory agencies are collaborating and communicating with one another in an ongoing effort to keep current with rapidly changing technology, as well as to share the very best and innovative practices, procedures, and protocols from state to state. The Commission made no changes in response to these comments.

The Sierra Club expressed support for the ability of the Commission to modify, suspend or terminate a permit, but recommended that the Commission include additional details in the rule, such as the right of the Commission to implement graduated maximum allowable injection pressure.

Language regarding the Commission's ability to modify, suspend or terminate an injection well permit has been included in §3.9 and §3.46 since their initial adoption. The procedure is basically the same no matter the cause. In addition, the Commission did not enumerate the details with regard to how the Commission might modify a permit because such modifications would be based on site-specific conditions. The Commission made no changes in response to this comment.

The Sierra Club recommended that the Commission include certain draft amendments considered by the Commission in 2013 regarding various issues such as public notice, integrity testing, and casing and cementing.

The Commission did circulate for informal comment in 2013 certain draft amendments to both §3.9 and §3.46 relating to issues such as public notice, integrity testing, and casing and cementing. However, the Commission has suspended work on those proposed amendments in order to address the issue of seismic activity. The Commission may revisit the issues raised in those earlier draft amendments at a later date. The Commission made no change in response to this comment.

The Sierra Club recommended that the Commission revise the rule to increase the disposal well permit application fee to cover the additional work required of Commission staff.

The Commission disagrees with this recommendation, as its application fees are established by the Texas Legislature in the statutes. The Commission made no change in response to this comment.

The EPA stated that the proposed regulations were reviewed by multiple Ground Water/Underground Injection Control program engineers and scientists, all of which applaud the Commission's efforts to ensure it has sufficient regulatory authority to respond to any event of this type where concerns may arise. The Commission appreciates this comment.

The EPA further commented that the proposed regulations require the permit applicant to calculate the estimated location of a five psi pressure front boundary after 10 years of injection, which would be used to define the area to be reviewed for information on seismic events on the USGS website as part of the application process. While the proposal preamble indicated this estimation is to be calculated using injection at the maximum requested permit injection volume, this is not stated in the proposed regulations. The EPA recommended that the Commission consider adding that requirement in §3.9(3)(B) and §3.46(b)(1)(C). As previously discussed, the Commission adopts wording changes that render this comment moot. The Commission made no change in response to this comment.

The EPA also expressed concern that the type of information necessary to conduct the pressure front boundary calculation may not be readily available, because it is difficult to reliably estimate the pressure front without an in situ measurement of transmissibility (generally a falloff test), and a static pressure measurement. EPA commented that, in areas where new oil and gas activity creates the need for new disposal wells, this type of information may not be well documented. If the pressure front is not realistically estimated, the search area for seismic events might be very small and, given the uncertainties in the USGS event locations (i.e., +/-10 miles) this approach would be of limited utility. EPA recommended that the Commission consider whether more detail needs to be provided on how to conduct this estimation, or consider establishing a minimum distance to be reviewed (e.g., 10 miles) which the applicant could opt to use if the formation information is not readily available.

The Sierra Club expressed agreement that the actual available information may not be sufficient and the distance assumed in the analysis may be too small.

One commenter expressed appreciation for the proposed rule amendments as a first step but was not convinced of their efficacy. Specifically, the commenter was concerned with calculation of the "10-year five pounds per square inch pressure front boundary," stating that assumptions and approximations used by permit applicants can be highly interpretative in nature and difficult for some operators to obtain and therefore would yield non-uniform and possibly misleading results. The commenter supports the requirement for reporting historical earthquake activity, the authority to request timely, detailed pressure and volume information for specific injection wells, and clarification of the ability of the Commission to modify injection permits. This commenter proposed changes to the proposed rules that would provide detailed methodology of calculation of the "10-year five pounds per square inch pressure front boundary" or require a simple, fixed distance search criteria for historical earthquakes, and detail how the Commission will use specified "additional data" in determination of earthquake risk.

The Commission appreciates these comments. As previously discussed, the Commission adopts changes to the rules that address some of the commenters' concerns. Specifically, the Commission agrees that the 10-year, five pounds per square inch pressure front boundary calculation may be onerous for some disposal well permit applicants and further agrees that a simpler, fixed-size circular survey centered on the proposed injection well location will be adequate for the purpose of performing a survey for historical earthquake occurrence. The Commission adopts changes to require applicants to conduct a survey of the USGS historical earthquake database in a circular area of 100 square miles centered on the location of the proposed injection well.

One commenter recommended that the Commission revise the rule to require monthly reporting of injection volumes and pressures along with maintaining daily injection volumes and pressures that may be requested at any time; clarify that the Commission may, as the result of an emergency hearing, require an operator to suspend operations pending further study; and indicate the Commission's commitment to continue to engage in, support, and review further scientific and engineering studies.

The Commission's rules already require that a permitted disposal well operator monitor the injection pressure and injection rate of each disposal well on at least a monthly basis and report the results of the monitoring to the Commission annually. However, the disposal well operator must typically monitor injection pressure and volume on a daily basis to ensure compliance with the limits on injection pressure and volume in the operator's permit. In addition, the Commission has the authority to require an operator to provide the records for injection pressure and volume to the Commission upon request. With respect to the recommendation that the Commission clarify that, as the result of an emergency hearing, the Commission may require an operator to suspend operations pending further study, the language regarding modification, suspension, and termination of a disposal well permit after notice and opportunity for hearing is sufficiently clear. With respect to the last recommendation of this commenter, the Commission presently plans to engage in, support, and review further scientific and engineering studies; however, such a statement is unnecessary in the rule language. The Commission made no change in response to these comments.

The City of Southlake recommended that the Commission revise the rule to provide for: (1) adequate public notice to elicit public comment and to engage public involvement through the permitting process; (2) accompanying hearing procedures; (3) and earnest appeals procedures for property owners who do not agree with or who are otherwise impacted by the Commission's permit determination in any case.

The Commission finds these comments are beyond the scope of this rulemaking and made no change in response to this comment.

With respect to the amendments in §3.9(6)(A)(vi) and §3.46(d)(1)(F), relating to modification, suspension or termination of a permit based on increased seismic activity, Chevron recommended that the Commission establish an appeals provision to allow an operator to present evidence to the Commission.

The Commission's regulations in Chapter 1 of this title (relating to Practice and Procedure), allow for "appeals" using the Commission's current hearing process and Commission decision, as well as the existing avenues through the court system. The Commission made no change in response to this comment.

CrownQuest and an individual expressed concerns with the proposed rule amendments with the calculation of the "10-year five pounds per square inch pressure front boundary", stating that assumptions and approximations used by permit applicants can be highly interpretative in nature and difficult for some operators to obtain and therefore would yield non-uniform and possibly misleading results. The commenters find the parameters used by the Commission to be arbitrary and not founded in sound science and engineering.

The Commission disagrees with the comment that the "10-year five pounds per square inch pressure front boundary" is arbitrary and not founded in sound science and engineering practice. Published research indicates that inducing earthquakes on preferentially oriented faults requires positive pressure differentials of as little as one pound per square inch to as much as 75 pounds per square inch. The Commission proposed five pounds per square inch as a conservative number. Further, calculation of the pressure front boundary after 10 years of injection at the maximum permitted injection rate was considered to be a reasonable measure of the lifetime amount of volume injected for a typical disposal well. Also, while understanding the wide range of possible values for real reservoir characteristics, the Commission expected operators would enter realistic values in the calculation to yield a first-order scientific and engineering calculation. Nonetheless, as previously discussed, the Commission adopts other changes to this wording; the language regarding calculation of a pressure front boundary around a proposed disposal well location has been moved to §3.9(3)(C) and §3.46(b)(1)(D) and will be required only in certain limited circumstances where additional information is necessary to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval.

CrownQuest suggested that in §3.9(3)(C) and §3.46(b)(1)(D) the word "may" be deleted and replaced with the words "will significantly" in the phrase " may increase the risk that fluids will be confined to the injection interval."

EPA commented that the transmission of pressure in the subsurface due to the injection of fluids affects a much greater area than the actual migration of the injected fluids, and expressed concern that not including language recognizing this pressure influence (which is the primary concern in induced seismicity events) may inadvertently limit the applicability of these changes.

The Commission agrees with the statement that transmission of pressure in the subsurface due to the injection of fluids affects a much greater area than the actual migration of the injected fluids, which is why the Commission originally proposed a pressure front calculation. However, due to other changes previously discussed, the Commission made no change with regard to these comments.

CrownQuest and Pioneer recommended that the Commission delete the phrase "suspected of or shown to be" in §3.9 (6)(A)(vi) and §3.46(d)(1)(F) and replace it with "demonstrated by reliable scientific and engineering data" in the phrase " injection is suspected of or shown to be causing seismic activity."

The Commission disagrees with the suggested wording change for §3.9(6)(A)(vi) and §3.46(d)(1)(F); however, the Commission adopts language to clarify that the trigger for the Commission to consider modification, suspension, or termination of a permit will be based on injection "likely to be or determined to be contributing to seismic activity."

CrownQuest commented that generally, disposal wells should be treated differently based on their proximity to population centers or the number of homes within the pressure front boundary.

The Commission disagrees with this comment; the Commission is concerned with the safety of all Texans, including those who live in low population areas. The Commission made no changes in response to this comment.

In a letter signed by the Honorable Judge Carlos Garcia, the Frio County Commissioners Court commented that the capacity of disposal into disposal wells is "exceeding environmental boundaries" and expressed concern that in the future, such disposal will result in well overflows or leaks. The Commissioners Court requested that the Commission review the Frio County area, in which the Commissioners Court stated are located wells permitted to dispose into shallow oil and gas producing formations which contain brackish water. The Commissioners Court also expressed concern with public safety and spills on roads in the county as well as pipelines, fractionation facilities, and other ancillary facilities, and referenced Chapter 361 of the Texas Health and Safety Code, regarding development of solid waste plans to protect and promote water, health, and public safety.

The Commission finds that these comments are beyond the scope of this rulemaking or outside the Commission's statutory authority. In determining whether to permit a disposal well, the Commission considers disposal capacity of an area, including the need for such disposal capacity and the existing pressure status of the interval into which the injection is proposed. The Commission also considers the presence of abandoned, unplugged or improperly plugged wells within the area of a proposed disposal well. The Commission does not permit injection into an underground source of drinking water as defined by the EPA and §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)). Section 3.30 defines an underground source of drinking water as "an aquifer or its portions which supplies drinking water for human consumption; or in which the groundwater contains fewer than 10,000 milligrams per liter total dissolved solids; and which is not an exempted aquifer." Such definition includes water defined as brackish. No disposal well in Frio County is permitted to inject into a USDW. The Commission made no changes in response to these comments.

DESCRIPTION OF RULE AS ADOPTED

As stated in the proposal preamble, the EPA estimates that there are 144,000 Class II injection wells in the United States. The Commission has permitted over 50,000 Class II injection wells in Texas since the 1930s. While few earthquakes have been documented over the past several decades relative to the large number of disposal wells in operation, seismic events have infrequently occurred in areas where there is coincident oil and gas activity. Therefore, the Commission adopts these rule amendments in order to require additional information in support of a permit application regarding historical seismic events in the vicinity of a proposed disposal well's location, as well as certain other information in the event the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. The USGS maintains an online, accessible data base of seismic events in the United States from 1973 to the present. Applicants for a disposal well permit under §3.9 or §3.46 as amended will be required to access the USGS earthquake search tool at http://earthquake.usgs.gov/earthquakes/search/ in order to retrieve data regarding the locations of historical seismic events within a specified area around the proposed disposal well location. The Commission also adopts these amendments to clarify that it has the authority to modify, suspend, or terminate a permit for just cause after notice and opportunity for hearing if injection is likely to be or determined to be contributing to seismic activity. Finally, the Commission adopts these rule amendments to authorize more frequent monitoring and reporting by operators of disposal well injection pressures and injection rates in the event certain conditions are present that may increase the risk that fluids will not be confined to the injection interval.

The Commission adopts amendments to §3.9(3) to add new subparagraph (B), with changes previously discussed, to state that the applicant shall include with the application for a disposal well permit under this section a printed copy or screenshot showing the results of a survey of information from the USGS indicating the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

The Commission adopts new §3.9(3)(C), with changes previously discussed, to state that the Commission may require an applicant for a disposal well permit to provide the Commission with additional information, such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Conditions that may increase the risk that fluids will not be confined to the injection interval may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS required in §3.9(3)(B).

The Commission amends §3.9(6)(A)(vi), with changes previously discussed, to include injection that is likely to be or determined to be contributing to seismic activity to the list of reasons for which the Commission may modify, suspend, or terminate a permit for saltwater or other oil and gas waste disposal for just cause after notice and opportunity for hearing.

The Commission amends §3.9(11)(A) and §3.9(11)(B) to state that the Commission may require more frequent monitoring and monitoring reporting to the Commission of the injection pressure and injection rate in the event that conditions described in §3.9(3)(C) and §3.46(b)(1)(D) exist which may increase the risk that fluids will not be confined to the injection interval. The Commission also amends §3.9(11)(B) to correct a typographical error in the existing rule.

The Commission amends §3.46 to incorporate similar language for disposal wells that are permitted under §3.46. Under §3.46, the Commission regulates injection into productive formations for either enhanced recovery or for disposal. The new language relating to seismic activity would apply only to those wells permitted under §3.46 for disposal purposes.

The Commission amends §3.46(b)(1) to add new subparagraphs (C) and (D). New subparagraph (C), adopted with changes previously discussed, requires the applicant to include with the permit application for injection for the purpose of disposal under this section a printed copy or screenshot showing the results of a survey of information from the USGS indicating the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

New §3.46(b)(1)(D), adopted with changes previously discussed, states that the Commission may require an applicant for a disposal well permit under this section to provide the Commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS required in §3.46(b)(1)(C).

The Commission amends §3.46(d)(1)(F), with changes previously discussed, to include injection that is likely to be or determined to be contributing to seismic activity to the list of reasons for which the Commission may modify, suspend, or terminate a permit for just cause after notice and opportunity for hearing.

The Commission amends §3.46(i)(1) and (2) to state that the Commission may require more frequent monitoring and monitoring reporting to the Commission of the injection pressure and injection rate.

The Commission adopts amendments to §3.9 and §3.46, pursuant to Texas Water Code, §26.131, which gives the Commission jurisdiction over pollution of surface or subsurface waters from oil and gas exploration, development, and production activities; Texas Water Code, Chapter 27, which authorizes the Commission to adopt and enforce rules relating to injection wells; Texas Natural Resources Code, §81.052, which authorizes the Commission to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission under Texas Natural Resources Code, §81.051; Texas Natural Resources Code, §85.042(b), which provides the Commission with the authority to, when necessary, make and enforce rules either general in their nature or applicable to particular fields for the prevention of actual waste of oil or operations in the field dangerous to life or property; Texas Natural Resources Code, §85.201, which authorizes the Commission to make and enforce rules for the conservation of oil and gas and prevention of waste of oil and gas; Texas Natural Resources Code, §85.202, which authorizes the Commission to adopt rules to prevent waste of oil and gas in drilling and producing operations; Texas Natural Resources Code, §91.101, which authorizes the Commission, in order to prevent pollution of surface water or subsurface water in the state, to adopt rules relating to the various oilfield operations, including activities associated with the drilling of injection water source wells which penetrate the base of usable quality water, and the discharge, storage, handling, transportation, reclamation, or disposal of oil and gas waste; and Texas Natural Resources Code, §91.602, which authorizes the Commission, in order to protect human health and the environment, to adopt and enforce rules relating to the generation, transportation, treatment, storage, and disposal of oil and gas hazardous waste.

Texas Water Code, §26.131, and Chapter 27; and Texas Natural Resources Code, §§81.052, 85.042(b), 85.201, 85.202, 91.101, and 91.602 are affected by the adopted amendments.

Statutory authority: Texas Water Code, §26.131, and Chapter 27; and Texas Natural Resources Code, §§81.052, 85.042(b), 85.201, 85.202, 91.101, and 91.602.

Cross-reference to statute: Texas Water Code, §26.131, and Chapter 27; and Texas Natural Resources Code, §§81.052, 85.042(b), 85.201, 85.202, 91.101, and 91.602.

Issued in Austin, Texas, on October 28, 2014.

§3.9.Disposal Wells.

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application.

(A) The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

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

(C) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

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

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone;

(vi) injection is likely to be or determined to be contributing to seismic activity; or

(vii) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A) - (C) of this section shall not apply.

(v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

(8) Casing. Disposal wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, geothermal resources, or freshwater resources.

(9) Special equipment.

(A) Tubing and packer. Wells drilled or converted for disposal shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 100 feet above the top of the permitted interval. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

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

(C) Exceptions. The director may grant an exception to any provision of this paragraph upon proof of good cause. If the director denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(10) Well record. Within 30 days after the completion or conversion of a disposal well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(11) Monitoring and reporting.

(A) The operator shall monitor the injection pressure and injection rate of each disposal well on at least a monthly basis, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(B) The results of the monitoring shall be reported annually to the commission on the prescribed form, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(C) All monitoring records shall be retained by the operator for at least five years.

(D) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(12) Testing.

(A) Purpose. The mechanical integrity of a disposal well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under subparagraph (E) of this paragraph.

(B) Applicability. Mechanical integrity of each disposal well shall be demonstrated in accordance with provisions of subparagraph (D) and subparagraph (E) of this paragraph prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in subparagraph (C) of this paragraph.

(C) Frequency.

(i) Each disposal well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(ii) In addition to testing required under clause (i), each disposal well shall be tested for mechanical integrity after every workover of the well.

(iii) A disposal well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the disposal well permit.

(iv) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in clauses (i) and (ii) of this subparagraph. Such testing schedule shall not apply to a disposal well for which a disposal well permit has been issued but the well has not been drilled or converted to disposal.

(D) Pressure tests.

(i) Test pressure.

(I) The test pressure for wells equipped to dispose through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(II) The test pressure for wells that are permitted for disposal through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(ii) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in clause (i) of this subparagraph prior to commencement of the test.

(iii) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(iv) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(v) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for disposal through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(vi) Test fluid.

(I) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes the use of a different test fluid for good cause.

(II) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(vii) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(I) the degree of pressure change during the test, if any;

(II) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(III) whether circumstances surrounding the administration of the test make the test inconclusive.

(E) Alternative testing methods.

(i) As an alternative to the testing required in subparagraph (B) of this paragraph, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by paragraph (11) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under subparagraph (B) of this paragraph at least once every ten years after January 1, 1990.

(ii) The commission or its delegate may grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(F) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(G) A complete record of all tests shall be filed in duplicate in the district office on the appropriate form within 30 days after the testing.

(H) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(13) Plugging. Disposal wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(14) Penalties.

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

(B) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance) for violation of this section.

§3.46.Fluid Injection into Productive Reservoirs.

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application.

(A) An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form.

(B) The applicant shall file the freshwater injection data form if fresh water is to be injected.

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

(D) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

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

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone;

(F) for a disposal well permit under this section, injection is likely to be or determined to be contributing to seismic activity; or

(G) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

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

(3) Exceptions. The commission or its delegate may grant an exception to any provision of this paragraph upon proof of good cause. If the commission or its delegate denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(h) Well record. Within 30 days after the completion or conversion of an injection well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(i) Monitoring and reporting.

(1) The operator shall monitor the injection pressure and injection rate of each injection well on at least a monthly basis, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section.

(2) The results of the monitoring shall be reported annually, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section, to the commission on the prescribed form.

(3) All monitoring records shall be retained by the operator for at least five years.

(4) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(j) Testing.

(1) Purpose. The mechanical integrity of an injection well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under paragraph (5) of this subsection.

(2) Applicability. Mechanical integrity of each injection well shall be demonstrated in accordance with provisions of paragraphs (4) and (5) of this subsection prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in paragraph (3) of this subsection.

(3) Frequency.

(A) Each injection well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(B) In addition to testing required under subparagraph (A), each injection well shall be tested for mechanical integrity after every workover of the well.

(C) An injection well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the injection permit.

(D) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in subparagraph (A) and subparagraph (B) of this paragraph. Such testing schedule shall not apply to an injection well for which an injection well permit has been issued but the well has not been drilled or converted to injection.

(4) Pressure tests.

(A) Test pressure.

(i) The test pressure for wells equipped to inject through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(ii) The test pressure for wells that are permitted for injection through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(B) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in subparagraph (A) of this paragraph prior to commencement of the test.

(C) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(D) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(E) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for injection through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(F) Test fluid.

(i) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes use of a different test fluid for good cause.

(ii) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(G) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(i) the degree of pressure change during the test, if any;

(ii) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(iii) whether circumstances surrounding the administration of the test make the test inconclusive.

(5) Alternative testing methods.

(A) As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by subsection (i) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under paragraph (3) of this subsection at least once every ten years after January 1, 1990.

(B) The commission or its delegate grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(6) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(7) A complete record of all tests shall be filed in duplicate in the district office within 30 days after the testing.

(8) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(k) Area Permits. A person may apply for an area permit that authorizes injection into new or converted wells located within the area specified in the area permit. For purposes of this subsection, the term "permit area" shall mean the area covered or proposed to be covered by an area permit. Except as specifically provided in this subsection, the provisions of subsections (a) - (j) of this section shall apply in the case of an area permit and all injection wells converted, completed, operated, or maintained in accordance with that permit. Except as otherwise specified in the area permit, once an area permit has been issued, the operator may apply to operate individual wells within the permit area as injection wells as specified in paragraph (3) of this subsection.

(1) An application for an area permit must be accompanied by an application for at least one injection well. The applicant must:

(A) identify the maximum number of injection wells that will be operated within the permit area;

(B) identify the depth(s) of usable-quality water within the permit area, as determined by the Groundwater Advisory Unit of the Oil and Gas Division;

(C) for each existing well in the permit area that may be converted to injection under the area permit, provide a wellbore diagram that specifies the casing and liner sizes and depths, packer setting depth, types and volumes of cement, and the cement tops for the well. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(D) provide a wellbore diagram(s) showing the type(s) of completion(s) that will be used for injection wells drilled after the date the application for the area permit is filed, including casing and liner sizes and depths and a statement indicating that such wells will be cemented in accordance with the cementing requirements of §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) (Statewide Rule 13);

(E) identify the type or types of fluids that are proposed to be injected into any well within the permit area;

(F) identify the depths from top to bottom of the injection interval throughout the permit area;

(G) specify the maximum surface injection pressure for any well in the permit area covered by the area permit;

(H) specify the maximum amount of fluid that will be injected daily into any individual well within the permit area as well as the maximum cumulative amount of fluid that will be injected daily in the permit area;

(I) in lieu of the area-of-review required under subsection (e) of this section and subject to the area-of-review variance provisions of subsection (e) of this section, review the data of public record for wells that penetrate the proposed injection interval within the permit area and the area 1/4 mile beyond the outer boundary of the permit area to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the injection interval into freshwater strata. The applicant shall identify in the application the wells which appear from the review of such public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has knowledge. The applicant shall also identify in the application the date of plugging of each abandoned well within the permit area and the area 1/4 mile beyond the outer boundary of the permit area; and

(J) furnish a map showing the location of each existing well that may be converted to injection under the area permit and the location of each well that the operator intends, at the time of application, to drill within the permit area for use for injection. The map shall be keyed to identify the configuration of all such wells as described in subparagraphs (C) and (D) of this paragraph.

(2) In lieu of the notice required under subsection (c)(1) of this section, notice of an area permit shall be given by providing a copy of the area permit application to each surface owner of record within the permit area; each commission-designated operator of a well located within one-half mile of the permit area; the county clerk of each county in which all or part of the permit area is located; and the city clerk or other appropriate city official of any incorporated city which is located wholly or partially within the permit area, on or before the date the application is mailed to or filed with the commission. Notice of an application for an area permit shall also be given in accordance with the requirements of subsection (c)(2). If, in connection with a particular application, the commission or its

delegate determines that another class of persons, such as adjacent surface owners or an appropriate underground water conservation district, should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class.

(3) Once an area permit has been issued and except as otherwise provided in the permit, no notice shall be required when an application for an individual injection well permit for any well covered by the area permit is filed.

(4) Prior to commencement of injection operations in any well within the permit area, the operator shall file an application for an individual well permit with the commission in Austin. The individual well permit application shall include the following:

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

(B) the location of any well drilled within 1/4 mile of the injection well after the date of application for the area permit and the status of any well located within 1/4 mile of the injection well that has been abandoned since the date the area permit was issued, including the plugging date if such well has been plugged;

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

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

(E) any other information required by the area permit.

(5) An individual well permit may be issued by the commission or its delegate in writing or, if no objection to the application is made by the commission or its delegate within 20 days of receipt of the application, the individual well permit shall be deemed issued.

(6) All individual injection wells covered by an area permit must be permitted in accordance with the requirements of this subsection and converted or completed, operated, maintained, and plugged in accordance with the requirements of this section and the area permit.

(l) Gas storage operations. Storage of gas in productive or depleted reservoirs shall be subject to the provisions of §3.96 of this title (relating to Underground Storage of Gas in Productive or Depleted Reservoirs).

(m) Plugging. Injection wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(n) Penalties.

(1) Violations of this section may subject the operator to penalties and remedies specified in Title 3 of the Natural Resources Code and any other statutes administered by the commission.

(2) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) for violation of 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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