WATER CODE

TITLE 2. WATER ADMINISTRATION

SUBTITLE D. WATER QUALITY CONTROL

CHAPTER 27. INJECTION WELLS

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 27.001. SHORT TITLE. This chapter may be cited as the Injection Well Act.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.002. DEFINITIONS. In this chapter:

(1) "Commission" means the Texas Commission on Environmental Quality.

(2) "Executive director" means the executive director of the commission.

(3) "Railroad commission" means the Railroad Commission of Texas.

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

(5) "Industrial and municipal waste" means any liquid, gaseous, solid, or other waste substance, or combination of these substances, which may cause or might reasonably be expected to cause pollution of fresh water and which result from:

(A) processes of industry, manufacturing, trade, or business;

(B) development or recovery of natural resources other than oil or gas; or

(C) disposal of sewage or other wastes of cities, towns, villages, communities, water districts, and other municipal corporations.

(6) "Oil and gas waste" means waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material.

(7) "Fluid" means a material or substance that flows or moves in a liquid, gaseous, solid, semi-solid, sludge, or other form or state.

(8) "Fresh water" means water having bacteriological, physical, and chemical properties which make it suitable and feasible for beneficial use for any lawful purpose.

(9) "Casing" means material lining used to seal off strata at and below the earth's surface.

(10) "Disposal well" means an injection well that is used for the injection of industrial and municipal waste or oil and gas waste.

(11) "Injection well" means an artificial excavation or opening in the ground made by digging, boring, drilling, jetting, driving, or some other method, and used to inject, transmit, or dispose of industrial and municipal waste or oil and gas waste into a subsurface stratum; or a well initially drilled to produce oil and gas which is used to transmit, inject, or dispose of industrial and municipal waste or oil and gas waste into a subsurface stratum; or a well used for the

injection of any other fluid; but the term does not include any surface pit, surface excavation, or natural depression used to dispose of industrial and municipal waste or oil and gas waste.

(12) "Extraction of minerals" means the use of an injection well for the development or recovery of natural resources other than resources subject to the jurisdiction of the railroad commission, and includes solution mining of minerals, in situ uranium mining, and mining of sulfur by the Frasch process, but does not include the solution mining of salt when leaching a cavern for the storage of hydrocarbons.

(13), (14) Renumbered as (11) and (12) by Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985.

(15) "Hazardous waste" has the meaning assigned to that term by Section 361.003, Health and Safety Code.

(16) "Production well" means a well used to recover uranium through in situ solution recovery, including an injection well used to recover uranium. The term does not include a well used to inject waste.

(17) "Monitoring well" means a well that is used to measure or monitor the level, quality, quantity, or movement of subsurface water.

(18) "Area permit" means a permit that authorizes the construction and operation of production and monitoring wells used in operations and restoration associated with in situ recovery of uranium.

(19) "Anthropogenic carbon dioxide":

(A) means:

(i) carbon dioxide that would otherwise have been released into the atmosphere that has been:

(a) stripped, segregated, or divided from any other fluid stream; or

(b) captured from an emissions source, including:

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

(2) an industrial source of emissions;

(ii) any incidental associated substance derived from the source material for, or from the process of capturing, carbon dioxide described by Subparagraph (i); and

(iii) any substance added to carbon dioxide described by Subparagraph (i) to enable or improve the process of injecting the carbon dioxide; and

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

(20) "Anthropogenic carbon dioxide injection well" means an injection well used to inject or transmit anthropogenic carbon dioxide into a reservoir.

(21) "Enhanced recovery operation" means the use of any process for the displacement of hydrocarbons from a reservoir other than primary recovery and includes the use of any physical, chemical, thermal, or biological process and any co-production project.

(22) "Geologic storage" means the underground storage of anthropogenic carbon dioxide in a reservoir.

(23) "Geologic storage facility" means the underground reservoir, underground equipment, injection wells, and surface buildings and equipment used or to be used for the geologic storage of anthropogenic carbon dioxide and all surface and subsurface rights and appurtenances necessary to the operation of a facility for the geologic storage of anthropogenic carbon dioxide. The term includes any reasonable and necessary areal buffer and subsurface monitoring zones, pressure fronts, and other areas as may be necessary for this state to receive delegation of any federal underground injection control program relating to the storage of carbon dioxide. The term does not include a pipeline used to transport carbon dioxide from the facility at which the carbon dioxide is captured to the geologic storage facility. The storage of carbon dioxide incidental to or as part of enhanced recovery

operations does not in itself automatically render a facility a geologic storage facility.

(24) "Oil or gas" means oil, natural gas, or gas condensate.

(25) "Reservoir" means a natural or artificially created subsurface sedimentary stratum, formation, aquifer, cavity, void, or coal seam.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 566, Sec. 14, eff. Sept. 1, 1985; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985; Acts 1991, 72nd Leg., ch. 14, Sec. 284(76), eff. Sept. 1, 1991; Acts 1991, 72nd Leg., 1st C.S., ch. 3, Sec. 1.067, eff. Aug. 12, 1991.
Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 1, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 1, eff. September 1, 2009.

Sec. 27.003. POLICY AND PURPOSE. It is the policy of this state and the purpose of this chapter to maintain the quality of fresh water in the state to the extent consistent with the public health and welfare and the operation of existing industries, taking into consideration the economic development of the state, to prevent underground injection that may pollute fresh water, and to require the use of all reasonable methods to implement this policy.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 2001, 77th Leg., ch. 965, Sec. 1.27, eff. Sept. 1, 2001.

SUBCHAPTER B. JURISDICTION OF COMMISSION

Sec. 27.011. PERMIT FROM COMMISSION. Unless the activity is subject to the jurisdiction of the railroad commission or

authorized by a rule of the commission, no person may continue utilizing an injection well or begin drilling an injection well or converting an existing well into an injection well to dispose of industrial and municipal waste, to extract minerals, or to inject a fluid without first obtaining a permit from the commission.

Amended by Acts 1977, 65th Leg., p. 1647, ch. 644, Sec. 10. Renumbered from Sec. 22.011 and amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985.

Sec. 27.012. APPLICATION FOR PERMIT. (a) The commission shall prescribe forms for application for a permit and shall make the forms available on request without charge.

(b) Applications for hazardous and nonhazardous disposal well permits shall be processed in accordance with this chapter for the benefit of the state and the preservation of its natural resources.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985; Acts 2001, 77th Leg., ch. 347, Sec. 1, eff. May 26, 2001.

Sec. 27.013. INFORMATION REQUIRED OF APPLICANT. An applicant shall furnish any information the executive director considers necessary to discharge his duties under this chapter and the rules of the commission.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985.

Sec. 27.014. APPLICATION FEE. With each application for a disposal well permit, the commission shall collect a fee in the amount provided by and under the terms of Section 5.701.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985; Acts 2001, 77th Leg., ch. 347, Sec. 1, eff. May 26, 2001. Amended by: Acts 2007, 80th Leg., R.S., Ch. 901 (H.B. 2654), Sec. 6, eff. September 1, 2007.

Sec. 27.015. LETTER FROM RAILROAD COMMISSION. (a) A person making application to the commission for a disposal well permit under this chapter shall submit with the application a letter from the railroad commission concluding that drilling or using the disposal well and injecting industrial and municipal waste into the subsurface stratum will not endanger or injure any known oil or gas reservoir.

(b) In a hearing on an application for a disposal well permit under this chapter, the commission may not proceed to hearing on any issues other than preliminary matters such as notice until the letter required from the railroad commission under Subsection (a) of this section is provided to the commission.

(c) The commission shall find that there will be no impairment of oil or gas mineral rights if the railroad commission has issued a letter under Subsection (a) that concludes that drilling and using the disposal well will not endanger or injure any known oil or gas reservoir.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114, eff. Sept. 1, 1985; Acts 1987, 70th Leg., ch. 638, Sec. 2, eff. Sept. 1, 1987; Acts 1993, 73rd Leg., ch. 802, Sec. 2, eff. June

18, 1993; Acts 1995, 74th Leg., ch. 76, Sec. 16.02, eff. Sept. 1, 1995.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 1238, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 27.016. INSPECTION OF WELL LOCATION. On receiving an application for a permit, the executive director shall have an inspection made of the location of the proposed disposal well to determine the local conditions and the probable effect of the well and shall determine the requirements for the setting of casing, as provided in Sections 27.051, 27.055, and 27.056 of this code.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.017. RECOMMENDATIONS FROM OTHER ENTITIES. (a) The executive director shall submit to the Department of State Health Services and to other persons which the commission may designate copies of every application received in proper form. These entities may make recommendations to the commission concerning any aspect of the application within 30 days.

(b) If an application is received in proper form for a permit for an injection well to dispose of industrial and municipal waste and the proposed location of the injection well is in the territory of a groundwater conservation district, the executive director shall submit a copy of the application to the governing body of the groundwater conservation district.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.114,

eff. Sept. 1, 1985; Acts 1987, 70th Leg., ch. 638, Sec. 3, eff. Sept. 1, 1987; Acts 1995, 74th Leg., ch. 76, Sec. 11.297, eff. Sept. 1, 1995. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 106 (H.B. 444), Sec. 1, eff. May 21, 2011.

Sec. 27.018. HEARING ON PERMIT APPLICATION. (a) If it is considered necessary and in the public interest, the commission may hold a public hearing on the application. The commission shall hold a hearing on a permit application for an injection well to dispose of industrial and municipal waste if a hearing is requested by a local government located in the county of the proposed disposal well site or by an affected person. In this subsection, "local government" has the meaning provided for that term by Chapter 26 of this code.

(b) The commission by rule shall provide for giving notice of the opportunity to request a public hearing on a permit application. The rules for notice shall include provisions for giving notice to local governments and affected persons. The commission shall define "affected person" by rule.

(c) Before the commission begins to hear testimony in a contested case as defined by Chapter 2001, Government Code, evidence must be placed in the record to demonstrate that proper notice regarding the hearing was given to affected persons. If mailed notice to an affected person is required, the commission or other party to the hearing shall place evidence in the record that notice was mailed to the address of the affected person included in the appropriate county tax rolls at the time of mailing. For the purposes of this subsection, the affidavit of the commission employee responsible for the mailing of the notice, attesting to the fact that notice was mailed to the address included in the tax rolls at the time of mailing, shall be prima facie evidence of proper mailing. The commission may not proceed with receipt of testimony in a contested case until there is compliance with this subsection.

(d) An application for an injection well to dispose of hazardous waste shall be subject to the pre-application local review process established by Section 361.063, Health and Safety Code, and to the requirements of Section 361.0791, Health and Safety Code.

(e) In addition to the requirements of Subsection (c), before any testimony is heard in a contested case regarding an application for a permit for an injection well to dispose of industrial and municipal waste that is proposed to be located in the territory of a groundwater conservation district, the record of the proceeding must include evidence that:

(1) a copy of each draft permit proposed by the executive director was provided to the governing body of the groundwater conservation district; and

(2) notice of the contested case hearing was mailed to the governing body of the groundwater conservation district.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 566, Sec. 15, eff. Sept. 1, 1985; Acts 1985, 69th Leg., ch. 795, Sec. 1.115, eff. Sept. 1, 1985; Acts 1987, 70th Leg., ch. 638, Sec. 4, eff. Sept. 1, 1987; Acts 1991, 72nd Leg., ch. 14, Sec. 284(77), eff. Sept. 1, 1991; Acts 1991, 72nd Leg., ch. 296, Sec. 1.22, eff. June 7, 1991; Acts 1995, 74th Leg., ch. 76, Sec. 5.95(49), eff. Sept. 1, 1995. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 106 (H.B. 444), Sec. 2, eff. May 21, 2011.

Sec. 27.019. RULES, ETC. (a) The commission shall adopt rules and procedures reasonably required for the performance of its powers, duties, and functions under this chapter.

(b) Copies of any rules under this chapter proposed by the commission shall before their adoption be sent to the railroad commission, the Texas Department of Health, and any other persons the commission may designate. Any agency or person to whom the copies of proposed rules are sent may submit comments

and recommendations to the commission and shall have reasonable time to do so as the commission may prescribe.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.116, eff. Sept. 1, 1985; Acts 1995, 74th Leg., ch. 76, Sec. 11.298, eff. Sept. 1, 1995.

Sec. 27.020. MINING OF SULFUR. The commission is authorized to develop a regulatory program with respect to the injection of fluid associated with the mining of sulfur by the Frasch process in accordance with the provisions of this chapter. The commission may not impose any requirements more stringent than those promulgated by the administrator of the United States Environmental Protection Agency pursuant to the federal Safe Drinking Water Act, 42 U.S.C. 300h et seq., as amended, unless the commission determines that more stringent regulations are necessary to protect human health or the environment.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.116, eff. Sept. 1, 1985.

Sec. 27.021. PERMIT FOR DISPOSAL OF BRINE FROM DESALINATION OPERATIONS OR OF DRINKING WATER TREATMENT RESIDUALS IN CLASS I INJECTION WELLS. (a) The commission may issue a permit to dispose of brine produced by a desalination operation or of drinking water treatment residuals in a Class I injection well if the applicant for the permit meets all the statutory and regulatory requirements for the issuance of a permit for a Class I injection well.

(a-1) A permit issued under this section may authorize the disposal of water treatment residuals produced by the desalination of seawater.

(b) The commission by rule shall provide for public notice and comment on an application for a permit authorized by this section. Notwithstanding Section 27.018, an application for a permit authorized by this section is not subject to the hearing requirements of Chapter 2001, Government Code.

Added by Acts 2003, 78th Leg., ch. 1118, Sec. 1, eff. Sept. 1, 2003. Amended by: Acts 2007, 80th Leg., R.S., Ch. 901 (H.B. 2654), Sec. 1, eff. September 1, 2007; Acts 2007, 80th Leg., R.S., Ch. 901 (H.B. 2654), Sec. 2, eff. September 1, 2007; Acts 2015, 84th Leg., R.S., Ch. 829 (H.B. 4097), Sec. 6, eff. June 17, 2015.

Sec. 27.023. JURISDICTION OVER IN SITU URANIUM APPLICATION DEVELOPMENT AND OPERATIONS. (a) The commission has exclusive jurisdiction over and shall regulate wells used during the development of permit applications to obtain required premining geologic, hydrologic, and water quality information.

(b) The commission shall require a well described by Subsection (a) to be registered with the commission. A well described by Subsection (a) is not subject to the commission's permitting, notice, and hearing requirements.

(c) If a well described by Subsection (a) is included in an area permit issued by the commission:

(1) the registration status of the well ceases; and

(2) the well is subject to all rules applicable to the area permit, including notice and hearing requirements.

Added by Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 2, eff. September 1, 2007.

Sec. 27.024. SHARING OF GEOLOGIC, HYDROLOGIC, AND WATER QUALITY DATA. (a) After a person developing an application for an area permit for an area located in a groundwater conservation district has identified a permit boundary, the person shall provide to that district:

(1) information regarding wells encountered by that person during the development of the area permit application that are not recorded in the public record;

(2) a map showing the locations of wells that are located within one-quarter mile of the location for the proposed permit and that are recorded in the public record;

(3) premining water quality information collected from wells described by Section 27.023(a);

(4) on a monthly basis, the amount of water produced from the wells described by Section 27.023(a); and

(5) a record of strata as described by Section 27.053, except confidential information described by Section 131.048, Natural Resources Code.

(b) A person may take not more than 90 days after the person receives the final information described by Subsection (a) to perform standard quality control and quality assurance procedures before the person submits the information to the groundwater conservation district.

Added by Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 2, eff. September 1, 2007.

Sec. 27.025. GENERAL PERMIT AUTHORIZING USE OF CLASS I INJECTION WELL TO INJECT NONHAZARDOUS BRINE FROM DESALINATION OPERATIONS OR NONHAZARDOUS DRINKING WATER TREATMENT RESIDUALS. (a) The commission may issue a general permit authorizing the use of a Class I injection well to inject nonhazardous brine from a desalination operation or to inject nonhazardous drinking water treatment residuals if the commission determines that the injection well and injection activities are more appropriately regulated under a general permit than under an individual permit based on findings that:

(1) the general permit has been drafted to ensure that it can be readily enforced and that the commission can adequately monitor compliance with the terms of the general permit; and

(2) the general permit will contain proper safeguards to protect ground and surface fresh water from pollution.

(a-1) A general permit issued under this section may authorize an injection well for the disposal of concentrate produced by the desalination of seawater. The general permit must include any requirements necessary to maintain delegation of the federal underground injection control program administered by the commission.

(b) The commission shall publish notice of a proposed general permit in one or more newspapers of statewide or regional circulation and in the Texas Register. The notice must include an invitation for written comments by the public to the commission regarding the proposed general permit and shall be published not later than the 30th day before the date the commission adopts the general permit. The commission by rule may require additional notice to be given.

(c) The commission may hold a public meeting to provide an additional opportunity for public comment. The commission shall give notice of the public meeting under this subsection by publication in the Texas Register not later than the 30th day before the date of the meeting.

(d) The commission shall issue a written response to comments on the general permit at the same time the commission issues or denies the permit. The response to comments is available to the public and shall be mailed to each person who made a comment.

(e) A general permit may provide that an owner of a Class I injection well may obtain authorization to use the well to inject nonhazardous brine from a desalination operation or to inject nonhazardous drinking water treatment residuals under a general permit by submitting to the commission written notice of intent to be covered by the general permit. The commission by rule shall establish the requirements for the notice of intent, including the information that an owner of an injection well subject to a general permit must submit to authorize the use of the well under the general permit. A general permit may

authorize the use of an injection well under the general permit on filing a complete and accurate notice of intent, including all information required by the commission's rules to be submitted, or it may specify a date or period of time after the commission receives the notice of intent, including the required information, on which the use of an injection well is authorized unless the executive director before that time notifies the owner that it is not eligible under the general permit.

(f) Authorization for the use of an injection well under a general permit does not confer a vested right. After written notice to the owner of an injection well, the executive director may suspend authorization for the use of the well under a general permit and may require the owner to obtain authorization for the use of the well under an individual permit.

(g) Notwithstanding the other provisions of this chapter, the commission, after hearing, shall deny or suspend authorization for the use of an injection well under a general permit if the commission determines that the owner's compliance history is classified as unsatisfactory according to commission standards under Sections 5.753 and 5.754 and rules adopted and procedures developed under those sections. A hearing under this subsection is not subject to the requirements relating to a contested case hearing under Chapter 2001, Government Code.

(h) A general permit may be issued for a term not to exceed 10 years. After notice and comment as provided by Subsections (b)-(d), a general permit may be amended, revoked, or canceled by the commission or renewed by the commission for an additional term or terms not to exceed 10 years each. A general permit remains in effect until amended, revoked, or canceled by the commission or, unless renewed by the commission, until expired. If before a general permit expires the commission proposes to renew that general permit, that general permit remains in effect until the date on which the commission takes final action on the proposed renewal.

(i) The commission may add or delete requirements for a general permit through a renewal or amendment process. The

commission shall provide a reasonable time to allow an owner of an injection well to make the changes necessary to comply with the additional requirements.

(j) The commission may impose a fee for the submission of a notice of intent to be covered by the general permit. The fee must be in the same amount as a fee collected under Section 27.014.

(k) The issuance, amendment, renewal, suspension, revocation, or cancellation of a general permit or the authorization for the use of an injection well under a general permit is not subject to the requirements relating to a contested case hearing under Chapter 2001, Government Code.

(l) The use or disposal of radioactive material under this section is subject to the applicable requirements of Chapter 401, Health and Safety Code.

(m) The commission may adopt rules as necessary to implement and administer this section.

Added by Acts 2007, 80th Leg., R.S., Ch. 901 (H.B. 2654), Sec. 3, eff. September 1, 2007.
Renumbered from Water Code, Section 27.023 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(112), eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 4.20, eff. September 1, 2011; Acts 2015, 84th Leg., R.S., Ch. 829 (H.B. 4097), Sec. 7, eff. June 17, 2015.

Sec. 27.026. DUAL AUTHORIZATION OF INJECTION WELLS TO INJECT NONHAZARDOUS BRINE FROM DESALINATION OPERATIONS OR NONHAZARDOUS DRINKING WATER TREATMENT RESIDUALS. (a) The commission may authorize by individual permit, by general permit, or by rule a Class V injection well for the injection of nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals into a Class II injection well that is also permitted by the railroad commission under Subchapter C.

(b) The commission and railroad commission by rule shall enter or amend a memorandum of understanding to implement and administer this section.

Added by Acts 2015, 84th Leg., R.S., Ch. 297 (H.B. 2230), Sec. 1, eff. September 1, 2015.

SUBCHAPTER C. OIL AND GAS WASTE; INJECTION WELLS

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 1806, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 27.031. PERMIT FROM RAILROAD COMMISSION. No person may continue using a disposal well or begin drilling a disposal well or converting an existing well into a disposal well to dispose of oil and gas waste without first obtaining a permit from the railroad commission.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.032. INFORMATION REQUIRED OF APPLICANT. The railroad commission shall require an applicant to furnish any information the railroad commission considers necessary to discharge its duties under this chapter.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.0321. APPLICATION FEE. (a) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the railroad commission a nonrefundable fee of $100.

(b) The fee collected under this section shall be deposited to the credit of the oil and gas regulation and cleanup fund as provided by Section 81.067, Natural Resources Code.

Added by Acts 1985, 69th Leg., ch. 239, Sec. 71, eff. Sept. 1, 1985. Amended by: Acts 2015, 84th Leg., R.S., Ch. 448 (H.B. 7), Sec. 45, eff. September 1, 2015.

Sec. 27.033. LETTER OF DETERMINATION. A person making application to the railroad commission for a permit under this chapter shall submit with the application a letter of determination from the railroad commission stating that drilling and using the disposal well and injecting oil and gas waste into the subsurface stratum will not endanger the freshwater strata in that area and that the formation or stratum to be used for the disposal is not freshwater sand.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.05, eff. September 1, 2011.

Sec. 27.034. RAILROAD COMMISSION RULES, ETC. (a) The railroad commission shall adopt rules and procedures reasonably required for the performance of its powers, duties, and functions under this chapter, including rules for notice and procedure of public hearings. The rules for notice shall include provisions for giving notice to local governments and affected persons. The railroad commission shall define "affected person" by rule.

(b) Copies of any rules under this chapter proposed by the railroad commission shall, before their adoption, be sent to the commission, the Texas Department of Health, and any other persons the railroad commission may designate. Any agency or person to whom the copies of proposed rules and regulations are

sent may submit comments and recommendations to the railroad commission and shall have reasonable time to do so as the railroad commission may prescribe.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.117, eff. Sept. 1, 1985; Acts 1995, 74th Leg., ch. 76, Sec. 11.299, eff. Sept. 1, 1995.

Sec. 27.035. JURISDICTION OVER IN SITU RECOVERY OF TAR SANDS. (a) The railroad commission has jurisdiction over the in situ recovery of tar sands and may issue permits for injection wells used for the in situ recovery of tar sands.

(b) A person may not begin to drill an injection well to be used in the in situ recovery of tar sands unless that person has a valid permit for the well issued by the railroad commission under this chapter.

(c) The railroad commission shall adopt rules that are necessary to administer and regulate the in situ recovery of tar sands.

(d) For purposes of regulation by the railroad commission, an injection well for the in situ recovery of tar sands is designated as a Class V well under the underground injection control program administered by the railroad commission.

Added by Acts 1983, 68th Leg., p. 754, ch. 184, Sec. 1, eff. Sept. 1, 1983.

Sec. 27.036. JURISDICTION OVER BRINE MINING. (a) In this section:

(1) "Brine mining" means the production of brine, including naturally occurring brine and brine extracted by the solution of a subsurface salt formation, for the purpose of extracting from a subsurface formation elements, salts, or other useful substances, not including:

(A) oil, gas, or any product of oil or gas as defined by Section 85.001, Natural Resources Code; or

(B) fluid oil and gas waste, as defined by Section 122.001, Natural Resources Code.

(2) "Class V brine injection well" means a well that injects spent, naturally occurring brine produced by a brine mining operation into the same formation from which it was withdrawn after extraction of elements, salts, or other useful substances, including halogens or halogen salts.

(b) The railroad commission has jurisdiction over brine mining and may issue permits for brine production wells and injection wells used for brine mining.

(c) A person may not begin to drill an injection well to be used for brine mining unless that person has a valid permit for the well issued by the railroad commission under this chapter.

(d) The railroad commission shall adopt rules that are necessary to administer and regulate brine mining.

(e) For purposes of regulation by the railroad commission, an injection well for brine mining of brine extracted by the solution of a subsurface salt formation is designated as a Class III well under the underground injection control program administered by the railroad commission.

(f) For purposes of regulation by the railroad commission, a Class V brine injection well is designated as a Class V well under the underground injection control program administered by the railroad commission.

(g) If rules or regulations adopted to govern Class V brine injection wells under the federal Safe Drinking Water Act (42 U.S.C. Section 300f et seq.) or another federal statute allow this state to seek primary enforcement authority under the underground injection control program, the railroad commission shall seek primacy to administer and enforce the program for Class V brine injection wells in this state.

(h) On delegation to the railroad commission of primary enforcement authority in this state over Class V brine injection

wells, a person may not begin to drill a Class V brine injection well unless that person has a valid permit for the well issued by the railroad commission under this chapter.

Added by Acts 1985, 69th Leg., ch. 921, Sec. 2, eff. Sept. 1, 1985. Amended by Acts 1987, 70th Leg., ch. 977, Sec. 32, eff. June 19, 1987. Amended by: Acts 2023, 88th Leg., R.S., Ch. 251 (S.B. 1186), Sec. 1, eff. May 27, 2023.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 879, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 27.037. JURISDICTION OVER CLOSED-LOOP GEOTHERMAL INJECTION WELLS. (a) In this section, "closed-loop geothermal injection well" means a closed system geothermal well used to circulate water, other fluids, or gases through the earth as a heat source or heat sink to generate power or heat or cool a structure.

(b) The railroad commission has jurisdiction over closed-loop geothermal injection wells and may issue permits for closed-loop geothermal injection wells, including individual permits, general permits, or permits by rule.

(c) A person may not begin drilling a closed-loop geothermal injection well unless that person holds a valid permit issued by the railroad commission under this section.

(d) For purposes of railroad commission regulation, a closed-loop geothermal injection well is designated as a Class V well under the underground injection control program administered by the railroad commission.

(e) The railroad commission shall adopt rules as necessary to administer this section and regulate closed-loop geothermal injection wells.

Added by Acts 2023, 88th Leg., R.S., Ch. 343 (S.B. 786), Sec. 1, eff. September 1, 2023.

SUBCHAPTER C-1. GEOLOGIC STORAGE AND ASSOCIATED INJECTION OF ANTHROPOGENIC CARBON DIOXIDE

Sec. 27.040. DEFINITION. In this subchapter, "offshore" means the area in the Gulf of Mexico seaward of the coast that is within three marine leagues of the coast.

Added by Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 7, eff. June 9, 2021.

Sec. 27.041. JURISDICTION. (a) The railroad commission has jurisdiction over the onshore and offshore injection and geologic storage of carbon dioxide in this state.

(b) Repealed by Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 15, eff. June 9, 2021.

(c) The railroad commission has jurisdiction over a well used for the purpose provided by Subsection (a) regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and is converted to the purpose provided by Subsection (a).

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 8, eff. June 9, 2021; Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 15, eff. June 9, 2021.

Sec. 27.042. APPLICABILITY. This subchapter does not apply to the injection of fluid through the use of a Class II injection well as defined by 40 C.F.R. Section 144.6(b) for the primary purpose of enhanced recovery operations.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009.

Sec. 27.043. PERMIT FROM RAILROAD COMMISSION. (a) A person may not begin drilling or operating an anthropogenic carbon dioxide injection well for geologic storage or constructing or operating a geologic storage facility regulated under this subchapter without first obtaining the necessary permits from the railroad commission.

(b) The railroad commission may not issue a permit under this subchapter for the conversion of a previously plugged and abandoned Class I injection well, including any associated waste plume, to a Class VI injection well.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 9, eff. June 9, 2021.

Sec. 27.044. INFORMATION REQUIRED OF APPLICANT. The railroad commission shall require an applicant to provide any information the railroad commission considers necessary to discharge its duties under this subchapter.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009.

Sec. 27.045. FEES. (a) The railroad commission may impose fees to cover the cost of:

(1) permitting, monitoring, and inspecting anthropogenic carbon dioxide injection wells for geologic storage and geologic storage facilities; and

(2) enforcing and implementing this subchapter and rules adopted by the railroad commission under this subchapter.

(b) Fees collected by the railroad commission under this section shall be deposited to the credit of the anthropogenic

carbon dioxide storage trust fund established under Section 121.003, Natural Resources Code.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 91 (S.B. 1303), Sec. 27.002(16), eff. September 1, 2011.

Sec. 27.046. LETTER OF DETERMINATION FROM RAILROAD COMMISSION. (a) The railroad commission may not issue a permit under rules adopted under this subchapter until the railroad commission issues to the applicant for the permit a letter of determination stating that drilling and operating the anthropogenic carbon dioxide injection well for geologic storage or operating the geologic storage facility will not injure any freshwater strata in that area and that the formation or stratum to be used for the geologic storage facility is not freshwater sand.

(b) To make the determination required by Subsection (a), the railroad commission shall review:

(1) the area of review and corrective action plans;

(2) any subsurface monitoring plans required during injection or post injection;

(3) any postinjection site care plans; and

(4) any other elements of the application reasonably required in order for the railroad commission to make the determination required by Subsection (a).

(c) The railroad commission shall adopt rules to implement and administer this section.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.06, eff. September 1, 2011; Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 10, eff. June 9, 2021.

Sec. 27.0461. LETTER OF DETERMINATION FROM COMMISSION. A person making an application to the railroad commission for a permit under this subchapter shall submit with the application a letter of determination from the commission concluding that drilling and operating an anthropogenic carbon dioxide injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by the commission.

Added by Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 11, eff. June 9, 2021.

Sec. 27.047. RULES. The railroad commission shall adopt rules and procedures reasonably required for the performance of its powers, duties, and functions under this subchapter, including rules for:

(1) the geologic storage and associated injection of anthropogenic carbon dioxide, including:

(A) geologic site characterization;

(B) area of review and corrective action;

(C) well construction;

(D) operation;

(E) mechanical integrity testing;

(F) monitoring;

(G) well plugging;

(H) postinjection site care;

(I) site closure; and

(J) long-term stewardship;

(2) the enforcement of this subchapter and rules adopted by the railroad commission under this subchapter; and

(3) the collection and administration of:

(A) fees imposed under Section 27.045;

(B) penalties imposed for a violation of this subchapter or rules adopted by the railroad commission under this subchapter; and

(C) funds received from financial responsibility mechanisms under Section 27.073.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 12, eff. June 9, 2021.

Sec. 27.048. CONSISTENCY WITH AND IMPLEMENTATION OF FEDERAL REQUIREMENTS. (a) Rules adopted by the railroad commission under this subchapter must be consistent with applicable rules or regulations adopted by the United States Environmental Protection Agency or another federal agency governing the injection and geologic storage of anthropogenic carbon dioxide.

(b) If rules or regulations adopted to govern the geologic storage and associated injection of anthropogenic carbon dioxide under the federal Safe Drinking Water Act (42 U.S.C. Section 300f et seq.) or another federal statute allow this state to seek primary enforcement authority under the underground injection control program, the railroad commission shall seek primacy to administer and enforce the program for the geologic storage and associated injection of anthropogenic carbon dioxide in this state, including onshore and offshore geologic storage and associated injection.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009. Amended by: Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 13, eff. June 9, 2021.

Sec. 27.049. MEMORANDUM OF UNDERSTANDING. The commission and the railroad commission, as necessary to comply with this subchapter, by rule shall:

(1) amend the memorandum of understanding recorded in 16 T.A.C. Section 3.30; or

(2) enter into a new memorandum of understanding.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009.

Sec. 27.050. FINANCIAL RESPONSIBILITY. (a) A person to whom a permit is issued under this subchapter must provide to the railroad commission annually evidence of financial responsibility that is satisfactory to the railroad commission.

(b) In determining whether the person is financially responsible, the railroad commission shall rely on:

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

(2) if the person is not required to file with the United States Securities and Exchange Commission a report described by Subdivision (1), the person's most recent audited financial statement.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 2, eff. September 1, 2009.

SUBCHAPTER D. ISSUANCE OF PERMITS: TERMS AND CONDITIONS

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 616, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 27.051. ISSUANCE OF PERMIT. (a) The commission may grant an application in whole or part and may issue the permit if it finds:

(1) that the use or installation of the injection well is in the public interest;

(2) that no existing rights, including, but not limited to, mineral rights, will be impaired;

(3) that, with proper safeguards, both ground and surface fresh water can be adequately protected from pollution;

(4) that the applicant has made a satisfactory showing of financial responsibility if required by Section 27.073 of this code;

(5) that the applicant has provided for the proper operation of the proposed hazardous waste injection well;

(6) that the applicant for a hazardous waste injection well not located in an area of industrial land use has made a reasonable effort to ensure that the burden, if any, imposed by the proposed hazardous waste injection well on local law enforcement, emergency medical or fire-fighting personnel, or public roadways, will be reasonably minimized or mitigated; and

(7) that the applicant owns or has made a good faith claim to, or has the consent of the owner to utilize, or has an option to acquire, or has the authority to acquire through eminent domain, the property or portions of the property where the hazardous waste injection well will be constructed.

(b) The railroad commission may grant an application for a permit under Subchapter C in whole or part and may issue the permit if it finds:

(1) that the use or installation of the injection well is in the public interest;

(2) that the use or installation of the injection well will not endanger or injure any oil, gas, or other mineral formation;

(3) that, with proper safeguards, both ground and surface fresh water can be adequately protected from pollution; and

(4) that the applicant has made a satisfactory showing of financial responsibility if required by Section 27.073.

(b-1) The railroad commission may issue a permit under Subchapter C-1 if it finds:

(1) that the injection and geologic storage of anthropogenic carbon dioxide will not endanger or injure any oil, gas, or other mineral formation;

(2) that, with proper safeguards, both ground and surface fresh water can be adequately protected from carbon dioxide migration or displaced formation fluids;

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

(4) that the reservoir into which the anthropogenic carbon dioxide is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic carbon dioxide from the reservoir; and

(5) that the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit.

(c) In the permit, the commission or railroad commission shall impose terms and conditions reasonably necessary to protect fresh water from pollution, including the necessary casing.

(d) The commission, in determining if the use or installation of an injection well is in the public interest under Subsection (a)(1), shall consider, but shall not be limited to the consideration of:

(1) compliance history of the applicant and related entities under the method for using compliance history developed by the commission under Section 5.754 and in accordance with the provisions of Subsection (e);

(2) whether there is a practical, economic, and feasible alternative to an injection well reasonably available; and

(3) if the injection well will be used for the disposal of hazardous waste, whether the applicant will maintain sufficient public liability insurance for bodily injury and property damage to third parties that is caused by sudden and non-sudden accidents or will otherwise demonstrate financial responsibility in a manner adopted by the commission in lieu of public liability insurance. A liability insurance policy which satisfies the policy limits required by the hazardous waste management regulations of the commission for the applicant's proposed pre-injection facilities shall be deemed "sufficient" under this subdivision if the policy:

(A) covers the injection well; and

(B) is issued by a company that is authorized to do business and to write that kind of insurance in this state and is solvent and not currently under supervision or in conservatorship or receivership in this state or any other state.

Text of subsec. (e) as amended by Acts 2001, 77th Leg., ch. 347, Sec. 2

(e) The commission shall establish a procedure for the preparation of comprehensive summaries of the applicant's compliance history, including the compliance history of any corporation or business entity managed, owned, or otherwise closely related to the applicant. The summaries shall be made available to the applicant and any interested person after the commission has completed its technical review of the permit application and prior to the promulgation of the public notice relating to the issuance of the permit. Evidence of compliance or noncompliance by an applicant for an injection well permit with environmental statutes and the rules adopted or orders or permits issued by the commission may be offered by any party at a hearing on the applicant's application and admitted into evidence subject to applicable rules of evidence. Evidence of

the compliance history of an applicant for an injection well permit may be offered by the executive director at a hearing on the application and admitted into evidence subject to the rules of evidence. All evidence admitted, including compliance history, shall be considered by the commission in determining whether to issue, amend, extend or renew a permit. If the commission concludes that the applicant's compliance history is unacceptable, the commission shall deny the permit.

Text of subsec. (e) as amended by Acts 2001, 77th Leg., ch. 965, Sec. 16.08

(e) Consistent with Sections 5.753 and 5.754 and rules adopted and procedures developed under those sections, the commission shall establish a procedure for preparing summaries of the applicant's compliance history. The summaries shall be made available to the applicant and any interested person after the commission has completed its technical review of the permit application and prior to the promulgation of the public notice relating to the issuance of the permit. Evidence of compliance or noncompliance by an applicant for an injection well for the disposal of hazardous waste with the rules adopted or orders or permits issued by the commission under this chapter may be offered by any party at a hearing on the applicant's application and admitted into evidence subject to applicable rules of evidence. In accordance with this subsection and Sections 5.753 and 5.754 and rules adopted and procedures developed under those sections, evidence of the compliance history of an applicant for an injection well may be offered at a hearing on the application and may be admitted into evidence, subject to the rules of evidence. All evidence admitted, including compliance history, shall be considered by the commission in determining whether to issue, amend, extend or renew a permit.

Text of subsec. (e) as amended by Acts 2001, 77th Leg., ch. 1161, Sec. 4

(e) The commission shall establish a procedure by rule for its preparation of compliance summaries relating to the history of compliance and noncompliance by the applicant with the rules adopted or orders or permits issued by the commission under this chapter for any injection well for which a permit has been issued under this chapter. A compliance summary must include as evidence of compliance information regarding the applicant's implementation of an environmental management system at the facility for which an authorization is sought. The compliance summaries shall be made available to the applicant and any interested person after the commission has completed its technical review of the permit application and prior to the promulgation of the public notice relating to the issuance of the permit. Evidence of compliance or noncompliance by an applicant for an injection well for the disposal of hazardous waste with the rules adopted or orders or permits issued by the commission under this chapter may be offered by any party at a hearing on the applicant's application and admitted into evidence subject to applicable rules of evidence. All evidence admitted, including compliance history, shall be considered by the commission in determining whether to issue, amend, extend or renew a permit. In this subsection, "environmental management system" has the meaning assigned by Section 5.127.

(f) In the issuance of a permit for a hazardous waste injection well into a salt dome, the commission shall consider the location of any geologic fault in the salt dome in the immediate proximity of the injection well bore, the presence of an underground water aquifer, and the presence of sulfur mines or oil and gas wells in the area.

(g)(1) The commission may not issue a permit for a hazardous waste injection well in a solution-mined salt dome cavern unless the United States Environmental Protection Agency

and the commission determine that sufficient rules are in place to regulate that activity.

(2) Before issuing a permit for a hazardous waste injection well in a solution-mined salt dome cavern, the commission by order must find that there is an urgent public necessity for the hazardous waste injection well. The commission, in determining whether an urgent public necessity exists for the permitting of the hazardous waste injection well in a solution-mined salt dome cavern, must find that:

(A) the injection well will be designed, constructed, and operated in a manner that provides at least the same degree of safety as required of other currently operating hazardous waste disposal technologies;

(B) consistent with the need and desire to manage within the state hazardous wastes generated in the state, there is a substantial or obvious public need for additional hazardous waste disposal capacity and the hazardous waste injection well will contribute additional capacity toward servicing that need;

(C) the injection well will be constructed and operated in a manner so as to safeguard public health and welfare and protect physical property and the environment;

(D) the applicant has demonstrated that groundwater and surface waters, including public water supplies, will be protected from the release of hazardous waste from the salt-dome waste containment cavern; and

(E) any other criteria required by the commission to satisfy that the test of urgency has been met.

(h) In determining whether the use or installation of an injection well is in the public interest under Subsection (a)(1), the commission shall consider the compliance history of the applicant in accordance with Subsection (e) and Sections 5.753 and 5.754 and rules adopted and procedures developed under those sections.

(i) For purposes of this subsection, "Edwards Aquifer" has the meaning assigned by Section 26.046(a). Except as otherwise

provided by this subsection, the commission may not authorize by rule or permit an injection well that transects or terminates in the Edwards Aquifer. The commission by rule may authorize:

(1) injection of groundwater withdrawn from the Edwards Aquifer;

(2) injections of storm water, flood water, or groundwater through improved sinkholes or caves located in karst topographic areas; or

(3) injections of water made in accordance with Section 1.44(e)(3), Chapter 626, Acts of the 73rd Legislature, Regular Session, 1993.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1983, 68th Leg., p. 5265, ch. 967, Sec. 14, eff. Sept. 1, 1983; Acts 1985, 69th Leg., ch. 566, Sec. 16, eff. Sept. 1, 1985; Acts 1987, 70th Leg., ch. 638, Sec. 5, eff. Sept. 1, 1987; Acts 1987, 70th Leg., ch. 977, Sec. 33, eff. June 19, 1987; Acts 1989, 71st Leg., ch. 1234, Sec. 1, eff. Aug. 28, 1989; Acts 1991, 72nd Leg., ch. 296, Sec. 1.23, eff. June 7, 1991; Acts 2001, 77th Leg., ch. 347, Sec. 2, eff. May 26, 2001; Acts 2001, 77th Leg., ch. 965, Sec. 16.08, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 966, Sec. 11.03(a), eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1161, Sec. 4, eff. Sept. 1, 2001.
Amended by: Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 3, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 91 (S.B. 1303), Sec. 27.001(66), eff. September 1, 2011; Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 4.21, eff. September 1, 2011; Acts 2019, 86th Leg., R.S., Ch. 585 (S.B. 520), Sec. 2, eff. September 1, 2019.

Sec. 27.0511. CONDITIONS OF CERTAIN PERMITS. (a) If the railroad commission receives an application for an injection well permit for a well that is to be used for enhanced recovery of oil, before a permit for the well may be granted, the

railroad commission shall require the applicant for the permit to provide written information relating to the material that the applicant plans to inject into the well for enhanced recovery purposes and to other material available to the applicant that might be used to inject into the well for enhanced recovery and shall make the determination required by Subsection (c) of this section.

(b) At the time the railroad commission receives an application under Subsection (a) of this section, it shall give notice to the commission that an application covered by this section is being considered and shall supply the commission with a copy of the application and a request for commission comment on the application. On receiving the information requested under Subsection (a) of this section, the railroad commission shall notify the commission that the information has been received and make the information available for the commission's inspection. The commission shall examine the application and information. Before the railroad commission considers the application, the commission shall submit to the railroad commission written comments regarding the use of fresh water under the permit and any problems that the commission anticipates will result from the use of fresh water under the permit. However, if the commission does not submit its written comments within 30 days after the request, the railroad commission may consider the application without the commission comments.

(c) On receiving the information required by Subsection (a) of this section, the railroad commission shall consider the information at the same time it considers whether or not to grant the permit, and if the applicant proposes to inject fresh water into the injection well for enhanced recovery, the railroad commission shall consider whether or not there is some other solid, liquid, or gaseous substance that is available to the applicant and that is economically and technically feasible for the applicant to use for enhanced recovery purposes.

(d) If the railroad commission finds that there is a solid, liquid, or gaseous substance other than fresh water available and economically and technically feasible for use in enhanced recovery under the permit, the railroad commission shall include as a condition of the permit, if granted, that the permittee use the other substance found to be available and economically and technically feasible and that the applicant not use fresh water or that the applicant use fresh water only to the extent specifically stated in the permit.

(e) This section does not apply to injection well permits that are in effect on September 1, 1983. If fresh water is being injected into an injection well in an enhanced recovery program that is in effect on September 1, 1983, and after that time, another substance or material is used for injection for a period of time, the injection well permit is not canceled, and a new permit under this chapter is not required if the operator plans at a later date to resume the use of fresh water for injection in that enhanced recovery program.

(f) Injection well permits for wells that are used for enhanced recovery remain in force until canceled by the railroad commission.

(g) Except as provided by Subsection (h), a person may not continue utilizing or begin utilizing industrial or municipal waste as an injection fluid for enhanced recovery purposes without first obtaining a permit from the commission.

(h) The railroad commission may authorize a person to utilize nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals as an injection fluid for enhanced recovery purposes without first obtaining a permit from the commission. The use or disposal of radioactive material under this subsection is subject to the applicable requirements of Chapter 401, Health and Safety Code.

Added by Acts 1983, 68th Leg., p. 5392, ch. 996, Sec. 1, eff. Sept. 1, 1983. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.118, 5.006, eff. Sept. 1, 1985.

Amended by: Acts 2007, 80th Leg., R.S., Ch. 901 (H.B. 2654), Sec. 4, eff. September 1, 2007.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 1061, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 27.0513. AREA PERMITS AND PRODUCTION AREAS FOR URANIUM MINING.

Sec. 27.0515. FACILITIES REQUIRED TO OBTAIN FEDERAL APPROVAL.

Sec. 27.0516. PERMITS FOR INJECTION WELLS THAT TRANSECT OR TERMINATE IN PORTION OF EDWARDS AQUIFER WITHIN EXTERNAL BOUNDARIES OF BARTON SPRINGS-EDWARDS AQUIFER CONSERVATION DISTRICT.

Sec. 27.052. COPIES OF PERMIT; FILING REQUIREMENTS. (a) The commission shall furnish the railroad commission and the Texas Department of Health with a copy of each permit the commission issues. The railroad commission shall furnish the commission with a copy of each permit the railroad commission issues and the executive director shall in turn forward copies to the Texas Department of Health.

(b) Before beginning injection operations, a person receiving a permit to inject industrial and municipal waste shall file a copy of the permit with the health authorities of the county, city, and town where the well is located.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.119, eff. Sept. 1, 1985; Acts 1995, 74th Leg., ch. 76, Sec. 11.300, eff. Sept. 1, 1995.

Sec. 27.053. RECORD OF STRATA. The commission or railroad commission may require a person receiving a permit or authorization by rule under this chapter to keep and furnish a complete and accurate record of the depth, thickness, and character of the different strata penetrated in drilling an injection well, monitoring well, or production well.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 3, eff. September 1, 2007.

Sec. 27.054. ELECTRIC OR DRILLING LOG. If an existing well is to be converted to an injection well, monitoring well, or production well, the commission or railroad commission may require the applicant to furnish an electric log or a drilling log of the existing well.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 4, eff. September 1, 2007.

Sec. 27.055. CASING REQUIREMENTS. The casing shall be set at the depth, with the materials, and in the manner required by the commission or railroad commission.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.056. FACTORS IN SETTING CASING DEPTH. Before setting the depth to which casing shall be installed, the commission or railroad commission shall consider:

(1) known geological and hydrological conditions and relationships;

(2) foreseeable future economic development in the area; and

(3) foreseeable future demand for the use of fresh water in the locality.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

SUBCHAPTER E. GENERAL POWERS

Sec. 27.071. POWER TO ENTER PROPERTY. Members of the commission and the railroad commission and employees of the commission and the railroad commission may enter public or private property to inspect and investigate conditions relating to injection well, monitoring well, disposal well, production well, or geologic storage activities within their respective jurisdictions or to monitor compliance with a rule, permit, or other order of the commission or railroad commission. Members or employees acting under the authority of this section who enter an establishment on public or private property shall observe the establishment's safety, internal security, and fire protection rules.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.120, eff. Sept. 1, 1985. Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 5, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 4, eff. September 1, 2009.

Sec. 27.072. POWER TO EXAMINE RECORDS. Members of the commission and the railroad commission and employees of the commission and railroad commission may examine and copy those

records or memoranda of a business they are investigating as provided by Section 27.071 that relate to the operation of an injection well, monitoring well, disposal well, production well, or geologic storage facility, or any other records required to be maintained by law.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.120, eff. Sept. 1, 1985. Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 6, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 4, eff. September 1, 2009.

Sec. 27.073. FINANCIAL RESPONSIBILITY. (a) A person to whom an injection well permit is issued may be required by the commission or railroad commission to maintain a performance bond or other form of financial security to ensure that:

(1) an abandoned injection well is properly plugged; or

(2) funds are available for plugging, postinjection site care, and closure of an anthropogenic carbon dioxide injection well subject to Subchapter C-1.

(a-1) Notwithstanding Subsection (a), a person to whom an in situ uranium mining injection well, monitoring well, or production well permit is issued shall be required by the commission to maintain a performance bond or other form of financial security to ensure that an abandoned well is properly plugged.

(b) Each state agency is authorized to receive funds as the beneficiary of a financial responsibility mechanism established under this section for the proper plugging of an injection well. Each state agency is authorized to expend such funds from a financial responsibility mechanism for the plugging of wells covered by that mechanism.

(b-1) The railroad commission is authorized to receive funds as the beneficiary of a financial responsibility mechanism

established under this chapter for the proper management of an anthropogenic carbon dioxide injection well or geologic storage facility. The funds shall be deposited to the credit of the anthropogenic carbon dioxide storage trust fund established under Section 121.003, Natural Resources Code.

(c) If liability insurance is required of an applicant, the applicant may not use a claims made policy as security unless:

(1) the policy provides for a right of extension by the insured upon cancellation or nonrenewal of the policy by the insurance company;

(2) the applicant places in escrow as provided by the commission an amount sufficient to enable the commission to exercise the right under the policy to purchase an extension of the policy from the date of cancellation or expiration of the policy that is reasonable in light of the degree and duration of the risks; and

(3) the applicant provides the commission with a limited power of attorney by which the commission is given an irrevocable power to exercise the applicant's right under the policy to purchase such an extension of the policy.

(d) In addition to other forms of financial security authorized by the rules of the commission, the commission may authorize an applicant to use the letter of credit form of financial security if either the issuing institution or another institution which guarantees payment under the letter:

(1) is a bank chartered by the state or by the federal government;

(2) is federally insured and its financial practices are regulated by the state or federal government; and

(3) is solvent and is not in receivership or owned or controlled by an entity that is insolvent or in receivership.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.120, eff. Sept. 1, 1985; Acts 1987, 70th Leg., ch. 638, Sec.

6, eff. Sept. 1, 1987; Acts 1989, 71st Leg., ch. 1234, Sec. 2, eff. Aug. 28, 1989. Amended by: Acts 2007, 80th Leg., R.S., Ch. 1118 (H.B. 3838), Sec. 7, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 5, eff. September 1, 2009; Acts 2021, 87th Leg., R.S., Ch. 460 (H.B. 1284), Sec. 14, eff. June 9, 2021.

SUBCHAPTER F. CIVIL AND CRIMINAL REMEDIES

Sec. 27.101. CIVIL PENALTY. (a) A person who violates any provision of this chapter under the jurisdiction of the railroad commission, any rule of the railroad commission made under this chapter, or any term, condition, or provision of a permit issued by the railroad commission under this chapter shall be subject to a civil penalty in any sum not exceeding $5,000 for each day of noncompliance and for each act of noncompliance. A violation under the jurisdiction of the commission is enforceable as provided by Chapter 7.

(b) The action may be brought by the railroad commission in any court of competent jurisdiction in the county where the offending activity is occurring or where the defendant resides.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1985, 69th Leg., ch. 795, Sec. 1.121, eff. Sept. 1, 1985; Acts 1997, 75th Leg., ch. 1072, Sec. 24, eff. Sept. 1, 1997.

Sec. 27.1011. ADMINISTRATIVE PENALTY. (a) If a person violates the provisions of this chapter or a rule, order, license, permit, or certificate issued under this chapter, the person may be assessed a civil penalty by the railroad commission.

(b) The penalty may not exceed $10,000 a day for each violation. Each day a violation continues may be considered a separate violation for purposes of penalty assessments.

(c) In determining the amount of the penalty, the railroad commission shall consider the permittee's history of previous violations of this chapter, the seriousness of the violation, any hazard to the health or safety of the public, and the demonstrated good faith of the permittee or person charged.

Added by Acts 1983, 68th Leg., p. 1411, ch. 286, Sec. 3, eff. Aug. 29, 1983.

Sec. 27.1012. PENALTY ASSESSMENT PROCEDURE. (a) A civil penalty may be assessed only after the person charged with a violation described under Section 27.1011 of this code has been given an opportunity for a public hearing.

(b) If a public hearing has been held, the railroad commission shall make findings of fact, and it shall issue a written decision as to the occurrence of the violation and the amount of the penalty that is warranted, incorporating, when appropriate, an order requiring that the penalty be paid.

(c) If appropriate, the railroad commission shall consolidate the hearings with other proceedings under this chapter.

(d) If the person charged with the violation fails to avail himself of the opportunity for a public hearing, a civil penalty may be assessed by the railroad commission after it has determined that a violation did occur and the amount of the penalty that is warranted.

(e) The railroad commission shall then issue an order requiring that the penalty be paid.

Added by Acts 1983, 68th Leg., p. 1411, ch. 286, Sec. 3, eff. Aug. 29, 1983.

Sec. 27.1013. PAYMENT OF PENALTY; REFUND. (a) On the issuance of an order finding that a violation has occurred, the railroad commission shall inform the permittee and any other person charged within 30 days of the amount of the penalty.

(b) Within the 30-day period immediately following the day on which the decision or order is final as provided in Subchapter F, Chapter 2001, Government Code, the person charged with the penalty shall:

(1) pay the penalty in full; or

(2) if the person seeks judicial review of either the amount of the penalty or the fact of the violation, or both:

(A) forward the amount to the railroad commission for placement in an escrow account; or

(B) in lieu of payment into escrow, post with the railroad commission a supersedeas bond in a form approved by the railroad commission for the amount of the penalty, such bond to be effective until all judicial review of the order or decision is final.

(c) If through judicial review of the decision or order it is determined that no violation occurred or that the amount of the penalty should be reduced or not assessed, the railroad commission shall, within the 30-day period immediately following that determination, if the penalty has been paid to the railroad commission, remit the appropriate amount to the person, with accrued interest, or where a supersedeas bond has been posted, the railroad commission shall execute a release of such bond.

(d) Failure to forward the money to the railroad commission within the time provided by Subsection (b) of this section results in a waiver of all legal rights to contest the violation or the amount of the penalty.

(e) Judicial review of the order or decision of the railroad commission assessing the penalty shall be under the substantial evidence rule and shall be instituted by filing a petition with the district court of Travis County, Texas, and not elsewhere, as provided for in Subchapter G, Chapter 2001, Government Code.

Added by Acts 1983, 68th Leg., p. 1411, ch. 286, Sec. 3, eff. Aug. 29, 1983. Amended by Acts 1995, 74th Leg., ch. 76, Sec. 5.95(53), (59), eff. Sept. 1, 1995.

Sec. 27.1014. RECOVERY OF PENALTY. Civil penalties owed under Sections 27.1011-27.1013 of this code may be recovered in a civil action brought by the attorney general at the request of the railroad commission.

Added by Acts 1983, 68th Leg., p. 1411, ch. 286, Sec. 3, eff. Aug. 29, 1983.

Sec. 27.102. INJUNCTION, ETC. (a) The railroad commission may enforce a provision of this chapter under the jurisdiction of the railroad commission, any valid rule made by the railroad commission under this chapter, or any term, condition, or provision of a permit issued by the railroad commission under this chapter by injunction or other appropriate remedy. The suit shall be brought in a court of competent jurisdiction in the county where the offending activity is occurring.

(b) The executive director may enforce a provision of this chapter under the jurisdiction of the commission, a commission rule adopted under this chapter, or a term, condition, or provision of a permit issued by the commission under this chapter as provided by Subchapter B, Chapter 7.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1997, 75th Leg., ch. 1072, Sec. 25, eff. Sept. 1, 1997.

Sec. 27.103. PROCEDURE. (a) At the request of the railroad commission, the attorney general shall institute and conduct a suit in the name of the State of Texas for injunctive relief or to recover the civil penalty, or for both the injunctive relief and civil penalty, authorized in Sections 27.101 and 27.102 of this chapter.

(b) Any party to a suit may appeal from a final judgment as in other civil cases.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981; Acts 1997, 75th Leg., ch. 1072, Sec. 26, eff. Sept. 1, 1997.

Sec. 27.104. EFFECT OF PERMIT ON CIVIL LIABILITY. The fact that a person has a permit issued under this chapter does not relieve him from any civil liability.

Amended by Acts 1977, 65th Leg., p. 2207, ch. 870, Sec. 1, eff. Sept. 1, 1977; Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981.

Sec. 27.105. CRIMINAL FINES. (a) A person who knowingly or intentionally violates a provision of this chapter under the jurisdiction of the railroad commission, a rule of the railroad commission, or a term, condition, or provision of a permit issued by the railroad commission under this chapter is subject to a fine of not more than $5,000 for each violation and for each day of violation. A violation under the jurisdiction of the commission is enforceable under Section 7.157.

(b) Venue for prosecution of an alleged violation is in the county in which the violation is alleged to have occurred or where the defendant resides.

Added by Acts 1981, 67th Leg., p. 3161, ch. 830, Sec. 1, eff. June 17, 1981. Amended by Acts 1985, 69th Leg., ch. 795, Sec. 1.1211, eff. Sept. 1, 1985; Acts 1997, 75th Leg., ch. 1072, Sec. 27, eff. Sept. 1, 1997.

SUBCHAPTER G. AQUIFER STORAGE AND RECOVERY PROJECTS

SUBCHAPTER H. AQUIFER RECHARGE PROJECTS

NATURAL RESOURCES CODE

TITLE 3. OIL AND GAS

SUBTITLE A. ADMINISTRATION

CHAPTER 81. RAILROAD COMMISSION OF TEXAS

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 81.001. DEFINITIONS. In this chapter:

(1) "Commission" means the Railroad Commission of Texas.

(2) "Commissioner" means any member of the Railroad Commission of Texas.

Acts 1977, 65th Leg., p. 2508, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.002. DEFINITION OF PERSON FOR CERTAIN PROVISIONS. In this chapter:

(1) "person" includes a corporation, as provided by Section 312.011, Government Code; and

(2) the definition of "person" assigned by Section 311.005, Government Code, does not apply.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.01, eff. April 1, 2011.

SUBCHAPTER B. ADMINISTRATIVE PROVISIONS

Sec. 81.01001. SUNSET PROVISION. (a) The Railroad Commission of Texas is subject to Chapter 325, Government Code (Texas Sunset Act). Unless continued in existence as provided by that chapter, the commission is abolished September 1, 2029.

(b) The Railroad Commission of Texas shall pay the costs incurred by the Sunset Advisory Commission in performing a review of the commission under this section. The Sunset Advisory Commission shall determine the costs, and the commission shall pay the amount of those costs promptly on receipt of a statement from the Sunset Advisory Commission detailing the costs.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011. Amended by: Acts 2009, 81st Leg., 1st C.S., Ch. 2 (S.B. 2), Sec. 1.14(b), eff. July 10, 2009; Acts 2011, 82nd Leg., R.S., Ch. 1232 (S.B. 652), Sec. 1.07(a), eff. June 17, 2011; Acts 2013, 83rd Leg., R.S., Ch. 1279 (H.B. 1675), Sec. 2.05, eff. June 14, 2013; Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 1, eff. September 1, 2017.

Sec. 81.01002. CHAIRMAN. The commissioners shall elect one commissioner as the chairman.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01003. QUALIFICATIONS FOR OFFICE. A commissioner must be:

(1) a qualified voter under the constitution and laws; and

(2) at least 25 years of age.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01004. PERSONAL FINANCIAL DISCLOSURE, STANDARDS OF CONDUCT, AND CONFLICT OF INTEREST. A commissioner is subject to the provisions of Chapter 572, Government Code, that apply to elected officers, including the requirements governing personal

financial statements, standards of conduct, and conflicts of interest.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01005. NAME AND SEAL. (a) The commissioners are known collectively as the "Railroad Commission of Texas."

(b) The seal of the commission contains a star of five points with the words "Railroad Commission of Texas" engraved on it.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01006. PROCEDURAL RULES. The commissioners may adopt all rules necessary for the commission's government and proceedings.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01007. SUPPLIES. The commissioners shall be furnished necessary furniture, stationery, supplies, and expenses, to be paid for on the order of the governor.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01008. SESSIONS. The commission may hold sessions at any place in this state when considered necessary.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01009. RECORDS RESEARCH FEE. The commission shall charge a person who requests an examination or search of commission records $5 for each half hour or fraction of a half hour that a commission employee spends in the examination or search unless the person requesting the search represents this state or a county.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01010. FEE FOR COPIES. (a) The commission may charge a fee for copies of papers provided by the commission to a person other than a department of this state.

(b) The fee for a copy of a paper, document, or record in the commission's office, including the certificate and seal to be applied by the secretary, is 15 cents for each 100 words.

(c) This section does not authorize the commission to charge a person a fee for a tariff sheet for the person's own use if the tariff sheet is in effect.

(d) The fees charged and collected under this section shall be accounted for by the secretary of the commission and paid into the treasury as provided by Chapter 603, Government Code.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01011. METHOD OF MAKING PAYMENTS TO COMMISSION. (a) The commission may authorize payment, as prescribed by the commission, of a regulatory fee, fine, penalty, or charge for goods and services by means of an electronic payment method or a credit card issued by a financial institution chartered by a state or the United States or issued by a nationally recognized credit organization approved by the commission. A payment by the authorized method may be made in person, by telephone, or through the Internet.

(b) The commission may require a person who makes a payment to the commission by means of an electronic payment method or credit card to pay a discount or service charge in an amount reasonable and necessary to reimburse the commission for the costs involved in processing the payment.

(c) The commission may adopt rules as necessary to implement this section.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01012. GIFTS, GRANTS, AND DONATIONS. (a) In this section, "contested case" has the meaning assigned by Section 2001.003, Government Code.

(b) The commission may apply for, request, solicit, contract for, receive, accept, and administer gifts, grants, and donations of money or other assistance from any source to carry out any commission purpose or power.

(c) The commission may not, under Subsection (b), accept a gift or donation of money or of property from a party in a contested case during the period from the inception of the contested case until the 30th day after the date a final order is signed in the contested case.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01013. CONFLICT OF INTEREST. (a) In this section, "Texas trade association" means a cooperative and voluntarily joined association of business or professional competitors in this state designed to assist its members and its industry or profession in dealing with mutual business or professional problems and in promoting their common interest.

(b) A person may not be an employee of the commission employed in a "bona fide executive, administrative, or professional capacity," as that phrase is used for purposes of

establishing an exemption to the overtime provisions of the federal Fair Labor Standards Act of 1938 (29 U.S.C. Section 201 et seq.) if:

(1) the person is an officer, employee, or paid consultant of a Texas trade association in a business or industry regulated by the commission; or

(2) the person's spouse is an officer, manager, or paid consultant of a Texas trade association in a business or industry regulated by the commission.

(c) A person who is required to register as a lobbyist under Chapter 305, Government Code, may not act as the general counsel to the commission.

(d) The commission shall provide to commissioners and to agency employees, as often as necessary, information regarding the requirements for office or employment under this chapter, including information regarding a person's responsibilities under applicable laws relating to standards of conduct for state officers or employees.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01014. EQUAL EMPLOYMENT OPPORTUNITY. (a) The commission shall prepare and maintain a written policy statement that implements a program of equal employment opportunity to ensure that all personnel decisions are made without regard to race, color, disability, sex, religion, age, or national origin.

(b) The policy statement must include:

(1) personnel policies, including policies relating to recruitment, evaluation, selection, training, and promotion of personnel, that show the intent of the commission to avoid the unlawful employment practices described by Chapter 21, Labor Code; and

(2) an analysis of the extent to which the composition of the commission's personnel is in accordance with

state and federal law and a description of reasonable methods to achieve compliance with state and federal law.

(c) The policy statement must:

(1) be updated annually;

(2) be reviewed by the Texas Workforce Commission civil rights division for compliance with Subsection (b); and

(3) be filed with the governor's office.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.01016. SEPARATION OF RESPONSIBILITIES. The commission shall develop and implement policies that clearly separate the policy-making responsibilities of the commissioners and the management responsibilities of the staff of the commission.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.011. CHIEF SUPERVISOR. (a) The commission shall employ a chief supervisor of its oil and gas division to assist the commission in enforcing the laws relating to the production, transportation, and conservation of oil and gas and rules and orders of the commission adopted under these laws.

(b) The chief supervisor also shall perform the duties of the pipeline expert as provided in the pipeline laws of this state.

Acts 1977, 65th Leg., p. 2508, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.012. QUALIFICATIONS OF CHIEF SUPERVISOR. In addition to other qualifications that may be required by the commission, a person appointed chief supervisor must have had at least five years' experience in some line of the oil or gas

business, or in some other business or profession that would provide the necessary knowledge and experience for the performance of his duties.

Acts 1977, 65th Leg., p. 2508, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.013. DEPUTY SUPERVISORS, ASSISTANTS, AND CLERICAL PERSONNEL. The commission may appoint a chief deputy supervisor, deputy supervisors, assistants, and clerical personnel necessary to execute the laws relating to oil and gas.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.014. QUALIFICATIONS OF CHIEF DEPUTY SUPERVISOR. A person appointed chief deputy supervisor must have had at least three years' experience in oil and gas field work.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.015. QUALIFICATIONS OF DEPUTY SUPERVISORS. Any person appointed deputy supervisor must have had at least two years' experience in oil and gas field work, including substantial experience in drilling or production.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.016. SALARIES. The salary of the chief supervisor, the chief deputy supervisor, and the deputy supervisors shall be the same as that provided in the General Appropriations Act.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.0165. SALARY OF SECRETARY. The salary of the secretary of the commission shall be the amount appropriated for that purpose by the legislature.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.02, eff. April 1, 2011.

Sec. 81.017. ADDITIONAL EMPLOYEES. The commission may employ gaugers, inspectors, investigators, supervisors, and clerical employees. These employees shall include a chief engineer, chief petroleum engineer, and an administrative chief, and their salaries shall be paid in the amounts provided in the General Appropriations Act.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 144, ch. 65, Sec. 1, eff. Sept. 1, 1981.

Sec. 81.018. PAYMENT OF SALARIES AND OTHER EXPENSES. (a) Salaries and other expenses necessary in the administration and enforcement of the oil and gas laws shall be paid by warrants drawn by the comptroller on the State Treasury from general revenue.

(b) Warrants for expenses shall be issued only on duly verified statements of the persons entitled to the funds and on approval of the chairman of the commission.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by: Acts 2015, 84th Leg., R.S., Ch. 470 (S.B. 757), Sec. 3, eff. September 1, 2015.

Sec. 81.019. DUTIES OF CHIEF SUPERVISOR, CHIEF DEPUTY SUPERVISOR, DEPUTY SUPERVISORS, AND OTHER EMPLOYEES. The chief

supervisor, chief deputy supervisor, deputy supervisors, and other employees shall perform the duties prescribed by the commission in conformity with rules of the commission relating to the production, transportation, and conservation of crude oil and natural gas.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.020. ADDITIONAL DUTIES OF CHIEF SUPERVISOR AND HIS DEPUTIES. (a) The chief supervisor and his deputies shall supervise the plugging of all abandoned wells and the shooting of wells and shall follow the rules of the commission relating to the production and conservation of oil and gas.

(b) The chief supervisor shall gather information and assist the commission in the performance of its duties under this title.

Acts 1977, 65th Leg., p. 2509, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.021. INTELLECTUAL PROPERTY. (a) The commission may:

(1) apply for, register, secure, hold, and protect under the laws of the United States or any state or nation:

(A) a patent for the invention, discovery, or improvement of any process, machine, manufacture, or composition of matter;

(B) a copyright for an original work of authorship fixed in any tangible medium of expression, known or later developed, from which it can be perceived, reproduced, or otherwise communicated, either directly or with the aid of a machine or device;

(C) a trademark, service mark, collective mark, or certification mark for a word, name, symbol, device, or slogan that the commission uses to identify and distinguish the

commission's goods and services from other goods and services; or

(D) other evidence of protection or exclusivity issued for intellectual property;

(2) contract with a person for the sale, lease, marketing, or other distribution of the commission's intellectual property;

(3) obtain under a contract described in Subdivision (2) a royalty, license right, or other appropriate means of securing reasonable compensation for the development or purchase of the commission's intellectual property; and

(4) waive or reduce the amount of compensation secured by contract under Subdivision (3) if the commission determines that the waiver or reduction will:

(A) further a goal or mission of the commission; and

(B) result in a net benefit to the state.

(b) Money paid to the commission under this section shall be deposited to the credit of the oil and gas regulation and cleanup fund as provided by Section 81.067.

Added by Acts 2017, 85th Leg., R.S., Ch. 72 (S.B. 1422), Sec. 1, eff. May 22, 2017.

SUBCHAPTER C. JURISDICTION, POWERS, AND DUTIES

Sec. 81.051. JURISDICTION OF COMMISSION. (a) The commission has jurisdiction over all:

(1) common carrier pipelines defined in Section 111.002 of this code in Texas;

(2) oil and gas wells in Texas;

(3) persons owning or operating pipelines in Texas;

(4) persons owning or engaged in drilling or operating oil or gas wells in Texas; and

(5) pipeline transportation and underground storage of hydrogen.

(b) Persons listed in Subsection (a) of this section and their pipelines and oil and gas wells are subject to the jurisdiction conferred by law on the commission.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1977, 65th Leg., p. 2694, ch. 871, art. II, Sec. 5, eff. Sept. 1, 1977. Amended by: Acts 2023, 88th Leg., R.S., Ch. 734 (H.B. 2847), Sec. 1, eff. September 1, 2023.

Sec. 81.052. RULES. The commission may adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the commission as set forth in Section 81.051, including such rules as the commission may consider necessary and appropriate to implement state responsibility under any federal law or rules governing such persons and their operations.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1979, 66th Leg., p. 19, ch. 12, Sec. 1, eff. March 15, 1979.

Sec. 81.0521. FEE FOR APPLICATION FOR EXCEPTION TO RAILROAD COMMISSION RULE. (a) With each application for an exception to any commission rule contained in Chapter 3 of Part I of Title 16 of the Texas Administrative Code, the applicant shall submit to the commission a fee of $150.

(b) The application fee for an exception to any commission rule may not be refunded.

(c) The proceeds from this fee, excluding any penalties collected in connection with the fee, shall be deposited to the oil and gas regulation and cleanup fund as provided by Section 81.067.

Added by Acts 1985, 69th Leg., ch. 239, Sec. 73, eff. Sept. 1, 1985. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 3, eff.

Sept. 1, 2001. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.01, eff. September 28, 2011; Acts 2015, 84th Leg., R.S., Ch. 448 (H.B. 7), Sec. 26, eff. September 1, 2015.

Sec. 81.0522. NATURAL GAS POLICY ACT APPLICATION FEE. (a) With each Natural Gas Policy Act (15 U.S.C. Sections 3301-3432) application, the applicant shall submit to the commission a fee. The commission shall set the application fee in an amount necessary to cover the cost of the commission's well category determination program but not to exceed $150.

(b) The fee for any Natural Gas Policy Act application may not be refunded.

Added by Acts 1985, 69th Leg., ch. 239, Sec. 73, eff. Sept. 1, 1985. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 4, eff. Sept. 1, 2001.

Sec. 81.0523. EXCLUSIVE JURISDICTION AND EXPRESS PREEMPTION. (a) In this section:

(1) "Commercially reasonable" means a condition that would allow a reasonably prudent operator to fully, effectively, and economically exploit, develop, produce, process, and transport oil and gas, as determined based on the objective standard of a reasonably prudent operator and not on an individualized assessment of an actual operator's capacity to act.

(2) "Oil and gas operation" means an activity associated with the exploration, development, production, processing, and transportation of oil and gas, including drilling, hydraulic fracture stimulation, completion, maintenance, reworking, recompletion, disposal, plugging and abandonment, secondary and tertiary recovery, and remediation activities.

(b) An oil and gas operation is subject to the exclusive jurisdiction of this state. Except as provided by Subsection

(c), a municipality or other political subdivision may not enact or enforce an ordinance or other measure, or an amendment or revision of an ordinance or other measure, that bans, limits, or otherwise regulates an oil and gas operation within the boundaries or extraterritorial jurisdiction of the municipality or political subdivision.

(c) The authority of a municipality or other political subdivision to regulate an oil and gas operation is expressly preempted, except that a municipality may enact, amend, or enforce an ordinance or other measure that:

(1) regulates only aboveground activity related to an oil and gas operation that occurs at or above the surface of the ground, including a regulation governing fire and emergency response, traffic, lights, or noise, or imposing notice or reasonable setback requirements;

(2) is commercially reasonable;

(3) does not effectively prohibit an oil and gas operation conducted by a reasonably prudent operator; and

(4) is not otherwise preempted by state or federal law.

(d) An ordinance or other measure is considered prima facie to be commercially reasonable if the ordinance or other measure has been in effect for at least five years and has allowed the oil and gas operations at issue to continue during that period.

Added by Acts 2015, 84th Leg., R.S., Ch. 30 (H.B. 40), Sec. 2, eff. May 18, 2015.

Sec. 81.053. COMMISSION POWERS. In the discharge of its duties and the enforcement of its jurisdiction under this title, the commission shall:

(1) institute suits;

(2) hear and determine complaints;

(3) require the attendance of witnesses and pay their expenses out of funds provided for that purpose;

(4) obtain the issuance of writs and process which may be necessary for the enforcement of its orders; and

(5) punish for contempt or disobedience of its orders in the manner provided for the district courts.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.0531. ADMINISTRATIVE PENALTY. (a) If a person violates provisions of this title which pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate which pertain to safety or the prevention or control of pollution and are issued under this title, the person may be assessed a civil penalty by the commission.

(b) The penalty may not exceed:

(1) $10,000 a day for each violation that is not related to pipeline safety; or

(2) $200,000 a day for each violation that is related to pipeline safety.

(b-1) Each day a violation continues may be considered a separate violation for purposes of penalty assessments, provided that the maximum penalty that may be assessed for any related series of violations related to pipeline safety may not exceed $2 million.

(c) In determining the amount of the penalty, the commission shall consider the permittee's history of previous violations, the seriousness of the violation, any hazard to the health or safety of the public, and the demonstrated good faith of the person charged. In determining the amount of the penalty for a violation of a provision of this title or a rule, order, license, permit, or certificate that relates to pipeline safety, the commission shall consider the guidelines adopted under Subsection (d).

(d) The commission by rule shall adopt guidelines to be used in determining the amount of the penalty for a violation of

a provision of this title or a rule, order, license, permit, or certificate that relates to pipeline safety. The guidelines shall include a penalty calculation worksheet that specifies the typical penalty for certain violations, circumstances justifying enhancement of a penalty and the amount of the enhancement, and circumstances justifying a reduction in a penalty and the amount of the reduction. The guidelines shall take into account:

(1) the permittee's history of previous violations, including the number of previous violations;

(2) the seriousness of the violation and of any pollution resulting from the violation;

(3) any hazard to the health or safety of the public;

(4) the degree of culpability;

(5) the demonstrated good faith of the person charged; and

(6) any other factor the commission considers relevant.

(e) A penalty collected under this section shall be deposited to the credit of the oil-field cleanup fund.

Added by Acts 1983, 68th Leg., p. 1407, ch. 286, Sec. 1, eff. Sept. 1, 1983. Amended by Acts 1999, 76th Leg., ch. 1089, Sec. 1, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 5, eff. Sept. 1, 2001. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 104 (S.B. 900), Sec. 1, eff. September 1, 2013.

Sec. 81.0532. PENALTY ASSESSMENT PROCEDURE. (a) A civil penalty may be assessed only after the person charged with a violation described under Section 81.0531 of this code has been given an opportunity for a public hearing.

(b) If a public hearing has been held, the commission shall make findings of fact, and it shall issue a written decision as to the occurrence of the violation and the amount of the penalty that is warranted, incorporating, when appropriate, an order requiring that the penalty be paid.

(c) If appropriate, the commission shall consolidate the hearings with other proceedings.

(d) If the person charged with the violation fails to avail himself of the opportunity for a public hearing, a civil penalty may be assessed by the commission after it has determined that a violation did occur and the amount of the penalty that is warranted.

(e) The commission shall then issue an order requiring that the penalty be paid.

Added by Acts 1983, 68th Leg., p. 1407, ch. 286, Sec. 1, eff. Sept. 1, 1983.

Sec. 81.0533. PAYMENT OF PENALTY; REFUND. (a) On the issuance of an order finding that a violation has occurred, the commission shall inform the person charged within 30 days of the amount of the penalty.

(b) Within the 30-day period immediately following the day on which the decision or order is final as provided in Subchapter F, Chapter 2001, Government Code, the person charged with the penalty shall:

(1) pay the penalty in full; or

(2) if the person seeks judicial review of either the amount of the penalty or the fact of the violation, or both:

(A) forward the amount to the commission for placement in an escrow account; or

(B) in lieu of payment into escrow, post with the commission a supersedeas bond in a form approved by the commission for the amount of the penalty, such bond to be effective until all judicial review of the order or decision is final.

(c) If through judicial review of the decision or order it is determined that no violation occurred or that the amount of the penalty should be reduced or not assessed, the commission shall, within the 30-day period immediately following that determination, if the penalty has been paid to the commission,

remit the appropriate amount to the person, with accrued interest, or where a supersedeas bond has been posted, the commission shall execute a release of such bond.

(d) Failure to forward the money to the commission within the time provided by Subsection (b) of this section results in a waiver of all legal rights to contest the violation or the amount of the penalty.

(e) Judicial review of the order or decision of the commission assessing the penalty shall be under the substantial evidence rule and shall be instituted by filing a petition with the district court of Travis County, Texas, and not elsewhere, as provided for in Subchapter G, Chapter 2001, Government Code.

Added by Acts 1983, 68th Leg., p. 1407, ch. 286, Sec. 1, eff. Sept. 1, 1983. Amended by Acts 1995, 74th Leg., ch. 76, Sec. 5.95(53), (59), eff. Sept. 1, 1995.

Sec. 81.0534. RECOVERY OF PENALTY. Civil penalties owed under Sections 81.0531-81.0533 of this code may be recovered in a civil action brought by the attorney general at the request of the commission.

Added by Acts 1983, 68th Leg., p. 1407, ch. 286, Sec. 1, eff. Sept. 1, 1983.

Sec. 81.054. ENFORCEMENT BY ATTORNEY GENERAL. (a) The attorney general shall enforce the provision of this title by injunction or other adequate remedy and as otherwise provided by law.

(b) If an action is instituted by the attorney general under this section alleging a violation of an NPDES permit or the failure to obtain an NPDES permit under Chapter 91 or Chapter 141 of the Natural Resources Code, the attorney general may not oppose intervention by a person who has standing to intervene, as provided by Rule 60, Texas Rules of Civil Procedure.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1995, 74th Leg., ch. 310, Sec. 5, eff. Aug. 28, 1995.

Sec. 81.055. PIPELINE SYSTEM FINANCIAL RESPONSIBILITY REQUIREMENTS.

Sec. 81.056. CONTAMINATION REPORT. (a) In this section:

(1) "Common carrier" has the meaning assigned by Section 111.002.

(2) "Owner of the land" or "landowner" means the first person who is shown on the appraisal roll of the appraisal district established for the county in which a tract of land is located as owning an interest in the surface estate of the land at the time a contamination report is required to be made under this section.

(b) If in the process of placing, repairing, replacing, or maintaining a pipeline a common carrier or an owner or operator of a pipeline observes or detects any petroleum-based contamination of soil or water in proximity to the pipeline, the common carrier or pipeline owner or operator shall report the contamination to the commission and the owner of the land on which the pipeline is located. Petroleum-based contamination of soil or water that is observed or detected is required to be reported under this subsection if:

(1) hydrocarbons are present on the surface of the water;

(2) at least five linear yards of soil have been affected by hydrocarbons; or

(3) soil affected by hydrocarbons extends beyond the face of the excavation in which the contamination is observed or detected.

(c) The contamination report:

(1) must be made not later than 24 hours after the common carrier or pipeline owner or operator observes or detects the contamination;

(2) must include the global positioning satellite coordinates of the location of the contamination; and

(3) may be made by telephone, facsimile, or electronic mail.

(d) Not later than the third business day after the date the commission receives the contamination report, a person authorized by the commission shall withdraw a soil sample from the contaminated land. The person is entitled to enter the land for the purpose of withdrawing the sample.

(e) A common carrier or pipeline owner or operator that makes a contamination report under this section is released from all liability for the contamination or the cleanup of the contamination covered by the report, except for any contamination caused by the common carrier or pipeline owner or operator.

(f) The commission shall adopt rules to implement this section.

(g) The commission may use money in the oil-field cleanup fund to implement this section. The amount of money in the fund the commission may use for that purpose may not exceed the amount of money in the fund that is derived from fees collected under Section 91.142 from common carriers or owners or operators of pipelines as determined annually by the commission.

Added by Acts 2005, 79th Leg., Ch. 339 (S.B. 1130), Sec. 1, eff. September 1, 2005. Amended by: Acts 2009, 81st Leg., R.S., Ch. 166 (H.B. 472), Sec. 1, eff. September 1, 2009. Acts 2009, 81st Leg., R.S., Ch. 166 (H.B. 472), Sec. 2, eff. September 1, 2009.

Sec. 81.059. APPOINTMENT OF MEDIATORS FOR INFORMAL COMPLAINTS. (a) The commission may provide for the appointment of a commission staff member as the mediator of an informal complaint filed with the commission, or the parties may agree to

employ and pay an independent mediator for the purpose of mediating the complaint.

(b) If the parties request that the mediation be conducted at a location other than the offices of the commission in Austin, the parties shall reimburse the commission for the commission's costs related to travel to those other locations.

(c) This section does not prohibit the commission from requiring that the parties participate in a formal complaint resolution proceeding.

(d) At least annually, the commission shall notify oil and gas producers of the existence of any informal complaint resolution process provided for by the commission.

(e) Filing an informal complaint is not a prerequisite for filing a formal complaint.

Added by Acts 2007, 80th Leg., R.S., Ch. 757 (H.B. 3273), Sec. 1, eff. September 1, 2007.

Sec. 81.0591. COMPLAINTS. (a) The commission shall maintain a file on each written complaint filed with the commission. The file must include:

(1) the name of the person who filed the complaint;

(2) the date the complaint is received by the commission;

(3) the subject matter of the complaint;

(4) the name of each person contacted in relation to the complaint;

(5) a summary of the results of the review or investigation of the complaint; and

(6) an explanation of the reason the file was closed, if the commission closed the file without taking action other than to investigate the complaint.

(b) The commission shall provide to the person filing the complaint and to each person who is a subject of the complaint a copy of the commission's policies and procedures relating to complaint investigation and resolution.

(c) The commission, at least quarterly until final disposition of the complaint, shall notify the person filing the complaint and each person who is a subject of the complaint of the status of the investigation unless the notice would jeopardize an undercover investigation.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.03, eff. April 1, 2011.

Sec. 81.0592. CONSUMER INTEREST INFORMATION. (a) The commission shall prepare information of consumer interest describing the regulatory functions of the commission and the procedures by which consumer complaints are filed with and resolved by the commission.

(b) The commission shall make the information available to the public and appropriate state agencies.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.03, eff. April 1, 2011.

Sec. 81.060. CONFIDENTIALITY PROVISIONS. (a) A confidentiality provision may not be required in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas that is entered into on or after September 1, 2007.

(b) A confidentiality provision in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas that was entered into before September 1, 2007, becomes unenforceable on the date the term of the contract expires.

Added by Acts 2007, 80th Leg., R.S., Ch. 757 (H.B. 3273), Sec. 1, eff. September 1, 2007.

Sec. 81.061. AUTHORITY TO ESTABLISH MARKET-BASED RATES.

Sec. 81.062. PUBLIC PARTICIPATION. The commission shall develop and implement policies that provide the public with a reasonable opportunity to appear before the commission and to speak on any issue under the jurisdiction of the commission.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.03, eff. April 1, 2011.

Sec. 81.063. ISSUANCE, SUSPENSION, OR REVOCATION OF LICENSE, PERMIT, OR CERTIFICATE. (a) If the commission proposes to suspend or revoke a person's license, permit, or certificate of public convenience and necessity, the person is entitled to a hearing before the commission.

(b) The commission may not:

(1) refuse to issue a license, permit, or certificate to a person because of the person's race, religion, color, sex, or national origin; or

(2) revoke or suspend the license, permit, or certificate of a person because of the person's race, religion, color, sex, or national origin.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.03, eff. April 1, 2011.

Sec. 81.064. POWERS OF COMMISSIONER OR DESIGNATED EMPLOYEE IN CASES BEFORE COMMISSION. (a) In a case before the commission, a commissioner, or an authorized commission employee, designated by the commission for that purpose, in the same manner as if the entire commission were present, may:

(1) hold a hearing;

(2) conduct an investigation;

(3) make a record of a hearing or investigation for the use and benefit of the commission;

(4) administer an oath;

(5) certify to an official act; and

(6) compel the attendance of a witness and the production of papers, books, accounts, and other pertinent documents and testimony.

(b) The record of a hearing or investigation made under this section that is certified to by the commissioner or employee has the same effect as if made before the commission. The commission shall determine a case in which the record is made under this section in the same manner as if the record had been made before the commission.

(c) The commission may punish for contempt a person who:

(1) refuses to comply with this section; or

(2) obstructs or attempts to obstruct a proceeding under this section.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.03, eff. April 1, 2011.

Sec. 81.065. ALTERNATIVE DISPUTE RESOLUTION POLICY. (a) The commission shall develop and implement a policy to encourage the use of appropriate alternative dispute resolution procedures under Chapter 2009, Government Code, to assist in the resolution of internal and external disputes under the commission's jurisdiction.

(b) The commission's procedures relating to alternative dispute resolution must conform, to the extent possible, to any model guidelines issued by the State Office of Administrative Hearings for the use of alternative dispute resolution by state agencies.

(c) The commission shall:

(1) coordinate the implementation of the policy adopted under Subsection (a);

(2) provide training as needed to implement the procedures for alternative dispute resolution; and

(3) collect information concerning the effectiveness of those procedures.

Added by Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 2, eff. September 1, 2017.

Sec. 81.066. OIL AND GAS DIVISION MONITORING AND ENFORCEMENT STRATEGIC PLAN. (a) The oil and gas division of the commission shall develop and publish an annual plan for each state fiscal year to use the oil and gas monitoring and enforcement resources of the commission strategically to ensure public safety and protect the environment.

(b) The commission shall seek input from stakeholders when developing each annual plan.

(c) The commission shall collect and maintain information that accurately shows the commission's oil and gas monitoring and enforcement activities. Each annual plan must include a report of the information collected by the commission that shows the commission's oil and gas monitoring and enforcement activities over time.

(d) The information described by Subsection (c) must include data regarding violations of statutes or commission rules that relate to oil and gas, including:

(1) the number, type, and severity of:

(A) violations the commission found to have occurred;

(B) violations the commission referred for enforcement to the section of the commission responsible for enforcement; and

(C) violations for which the commission imposed a penalty or took other enforcement action;

(2) the number of major violations for which the commission imposed a penalty or took other enforcement action; and

(3) the number of repeat major violations, categorized by individual oil or gas lease, if applicable.

(e) The commission shall publish each annual plan on the commission's Internet website not later than July 1 of the year

preceding the state fiscal year in which the commission implements the plan.

Added by Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 2, eff. September 1, 2017.

Sec. 81.067. OIL AND GAS REGULATION AND CLEANUP FUND. (a) The oil and gas regulation and cleanup fund is created as an account in the general revenue fund of the state treasury.

(b) Repealed by Acts 2019, 86th Leg., R.S., Ch. 55 (H.B. 2675), Sec. 3, eff. September 1, 2019.

(c) The fund consists of:

(1) proceeds from bonds and other financial security required by this chapter and benefits under well-specific plugging insurance policies described by Section 91.104(c) that are paid to the state as contingent beneficiary of the policies, subject to the refund provisions of Section 91.1091, if applicable;

(2) private contributions, including contributions made under Section 89.084;

(3) expenses collected under Section 89.083;

(4) fees imposed under Section 85.2021;

(5) costs recovered under Section 91.457 or 91.459;

(6) proceeds collected under Sections 89.085 and 91.115;

(7) interest earned on the funds deposited in the fund;

(8) oil and gas waste hauler permit application fees collected under Section 29.015, Water Code;

(9) costs recovered under Section 91.113(f);

(10) hazardous oil and gas waste generation fees collected under Section 91.605;

(11) oil-field cleanup regulatory fees on oil collected under Section 81.116;

(12) oil-field cleanup regulatory fees on gas collected under Section 81.117;

(13) fees for a reissued certificate collected under Section 91.707;

(14) fees collected under Section 91.1013;

(15) fees collected under Section 89.088;

(16) fees collected under Section 91.142;

(17) fees collected under Section 91.654;

(18) costs recovered under Sections 91.656 and 91.657;

(19) fees collected under Section 81.0521;

(20) fees collected under Sections 89.024 and 89.026;

(21) legislative appropriations;

(22) any surcharges collected under Section 81.070;

(23) fees collected under Section 91.0115;

(24) fees collected under Subchapter E, Chapter 121, Utilities Code;

(25) fees collected under Section 27.0321, Water Code;

(26) fees collected under Section 81.071; and

(27) money collected under Section 81.021.

Added by Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.02, eff. September 28, 2011. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 835 (H.B. 7), Sec. 10, eff. June 14, 2013; Acts 2013, 83rd Leg., R.S., Ch. 1075 (H.B. 3309), Sec. 1, eff. September 1, 2013; Acts 2015, 84th Leg., R.S., Ch. 448 (H.B. 7), Sec. 27, eff. September 1, 2015; Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 3, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 72 (S.B. 1422), Sec. 2, eff. May 22, 2017; Acts 2017, 85th Leg., R.S., Ch. 324 (S.B. 1488), Sec. 13.001, eff. September 1, 2017; Acts 2019, 86th Leg., R.S., Ch. 55 (H.B. 2675), Sec. 3, eff. September 1, 2019; Reenacted and amended by Acts 2019, 86th Leg., R.S., Ch. 467 (H.B. 4170), Sec. 11.001, eff. September 1, 2019.

Sec. 81.068. PURPOSES OF OIL AND GAS REGULATION AND CLEANUP FUND. Money in the oil and gas regulation and cleanup

fund may be used by the commission or its employees or agents for any purpose related to the regulation of oil and gas development, including oil and gas monitoring and inspections, oil and gas remediation, and oil and gas well plugging, the study and evaluation of electronic access to geologic data and surface casing depths necessary to protect usable groundwater in this state, the administration of pipeline safety and regulatory programs, public information and services related to those activities, and administrative costs and state benefits for personnel involved in those activities.

Added by Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.02, eff. September 28, 2011. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 835 (H.B. 7), Sec. 11, eff. June 14, 2013; Acts 2013, 83rd Leg., R.S., Ch. 1075 (H.B. 3309), Sec. 2, eff. September 1, 2013; Reenacted and amended by Acts 2015, 84th Leg., R.S., Ch. 448 (H.B. 7), Sec. 28, eff. September 1, 2015. Amended by: Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 4, eff. September 1, 2017.

Sec. 81.069. REPORTING ON PROGRESS IN MEETING PERFORMANCE GOALS FOR THE OIL AND GAS REGULATION AND CLEANUP FUND. (a) The commission, through the legislative appropriations request process, shall establish specific performance goals for the oil and gas regulation and cleanup fund for the next biennium, including goals for each quarter of each state fiscal year of the biennium for the number of:

(1) orphaned wells to be plugged with state-managed funds;

(2) abandoned sites to be investigated, assessed, or cleaned up with state funds; and

(3) surface locations to be remediated.

(b) The commission shall provide quarterly reports to the Legislative Budget Board that include:

(1) the following information with respect to the period since the last report was provided as well as cumulatively:

(A) the amount of money deposited in the oil and gas regulation and cleanup fund;

(B) the amount of money spent from the fund for the purposes described by Subsection (a);

(C) the balance of the fund; and

(D) the commission's progress in meeting the quarterly performance goals established under Subsection (a) and, if the number of orphaned wells plugged with state-managed funds, abandoned sites investigated, assessed, or cleaned up with state funds, or surface locations remediated is at least five percent less than the number projected in the applicable goal established under Subsection (a), an explanation of the reason for the variance; and

(2) any additional information or data requested in writing by the Legislative Budget Board.

(c) The commission shall submit to the legislature and make available to the public, annually, a report that reviews the extent to which money provided under Section 81.067 has enabled the commission to better protect the environment through oil-field cleanup activities. The report must include:

(1) the performance goals established under Subsection (a) for that state fiscal year, the commission's progress in meeting those performance goals, and, if the number of orphaned wells plugged with state-managed funds, abandoned sites investigated, assessed, or cleaned up with state funds, or surface locations remediated is at least five percent less than the number projected in the applicable goal established under Subsection (a), an explanation of the reason for the variance;

(2) the number of orphaned wells plugged with state-managed funds, by region;

(3) the number of wells orphaned, by region;

(4) the number of inactive wells not currently in compliance with commission rules, by region;

(5) the status of enforcement proceedings for all wells in violation of commission rules and the period during which the wells have been in violation, by region in which the wells are located;

(6) the number of surface locations remediated, by region;

(7) a detailed accounting of expenditures of money in the fund for oil-field cleanup activities, including expenditures for plugging of orphaned wells, investigation, assessment, and cleaning up of abandoned sites, and remediation of surface locations;

(8) the method by which the commission sets priorities by which it determines the order in which orphaned wells are plugged;

(9) a projection of the amount of money needed for the next biennium for plugging orphaned wells, investigating, assessing, and cleaning up abandoned sites, and remediating surface locations; and

(10) the number of sites successfully remediated under the voluntary cleanup program under Subchapter O, Chapter 91, by region.

Added by Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.02, eff. September 28, 2011.

Sec. 81.070. ESTABLISHMENT OF SURCHARGES ON FEES. (a) Except as provided by Subsection (b), the commission by rule shall provide for the imposition of reasonable surcharges as necessary on fees imposed by the commission that are required to be deposited to the credit of the oil and gas regulation and cleanup fund as provided by Section 81.067 in amounts sufficient to enable the commission to recover the costs of performing the functions specified by Section 81.068 from those fees and surcharges.

(b) The commission may not impose a surcharge on an oil-field cleanup regulatory fee on oil collected under Section

81.116 or an oil-field cleanup regulatory fee on gas collected under Section 81.117.

(c) The commission by rule shall establish a methodology for determining the amount of a surcharge that takes into account:

(1) the time required for regulatory work associated with the activity in connection with which the surcharge is imposed;

(2) the number of individuals or entities from which the commission's costs may be recovered;

(3) the effect of the surcharge on operators of all sizes, as measured by the number of oil or gas wells operated;

(4) the balance in the oil and gas regulation and cleanup fund; and

(5) any other factors the commission determines to be important to the fair and equitable imposition of the surcharge.

(d) The commission shall collect a surcharge on a fee at the time the fee is collected.

(e) A surcharge collected under this section shall be deposited to the credit of the oil and gas regulation and cleanup fund as provided by Section 81.067.

(f) A surcharge collected under this section shall not exceed an amount equal to 185 percent of the fee on which it is imposed.

Added by Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.02, eff. September 28, 2011.

Sec. 81.071. PIPELINE SAFETY AND REGULATORY FEES. (a) The commission by rule may establish pipeline safety and regulatory fees to be assessed for permits or registrations for pipelines under the jurisdiction of the commission's pipeline safety and regulatory program.

(b) The commission may establish fees to be assessed annually against permit or registration holders, as well as

individual fees for new permits or registrations, permit or registration renewals, and permit or registration amendments.

(c) The fees must be in amounts that in the aggregate are sufficient to support all pipeline safety and regulatory program costs, including:

(1) permitting or registration costs;

(2) administrative costs; and

(3) costs of employee salaries and benefits.

(d) The commission by rule must establish the method or methods by which the fees will be calculated and assessed so that fee amounts will reflect the time spent and costs incurred to perform the regulatory work associated with permitting or registering pipelines, the effects of required fees on operators of all sizes, and other factors the commission determines are important to the fair imposition of the fees. The commission may base the fees on any factor the commission considers necessary to efficiently and fairly recover the pipeline safety and regulatory program's costs, including:

(1) the length of the pipeline;

(2) the number of new permits or registrations, permit or registration renewals, or permit or registration amendments; or

(3) the number of pipeline systems.

(e) The commission by rule may establish a reasonable late payment penalty for a fee charged under this section.

(f) The authority provided by this section is in addition to the authority provided by Section 121.211, Utilities Code, and the commission shall consider any fees assessed under that section in establishing the fees to be assessed under this section.

(g) A fee collected under this section shall be deposited to the credit of the oil and gas regulation and cleanup fund as provided by Section 81.067.

Added by Acts 2017, 85th Leg., R.S., Ch. 57 (H.B. 1818), Sec. 5, eff. September 1, 2017.

Sec. 81.075. TEXAS HYDROGEN PRODUCTION POLICY COUNCIL. (a) In this section, "council" means the Texas hydrogen production policy council.

(b) The Texas hydrogen production policy council is established within the commission to study and make recommendations relating to the commission's policy framework for hydrogen energy development.

(c) The council is composed of:

(1) the chair of the commission or the chair's designee; and

(2) not more than 11 members appointed by the commission to represent as many different types of participants as possible, including at least three but not more than five representatives from the hydrogen industry.

(d) The commissioner or the commissioner's designee is the chair of the council.

(e) A member of the council is not entitled to compensation or reimbursement of expenses for service on the council.

(f) The council:

(1) shall study the development of hydrogen industries in this state, including the development of facilities for the production, pipeline transportation, and storage of hydrogen;

(2) shall monitor regional efforts for the application and development of a regional clean hydrogen hub authorized under the Infrastructure Investment and Jobs Act (Pub. L. No. 117-58) or another federal act;

(3) may coordinate actions with other state agencies in supporting an application for a regional clean hydrogen hub described by Subdivision (2); and

(4) shall develop a state plan for hydrogen production oversight by the commission.

(g) The council shall make recommendations to the legislature relating to legislative changes needed for the oversight and regulation of production, pipeline transportation, and storage of hydrogen.

(h) The council is abolished and this section expires on January 1, 2030.

Added by Acts 2023, 88th Leg., R.S., Ch. 734 (H.B. 2847), Sec. 2, eff. September 1, 2023.

SUBCHAPTER D. WITNESSES

Sec. 81.091. INCRIMINATING TESTIMONY. If a witness fails or refuses to appear on being summoned, to answer any question he is asked, or to produce any record or data required by subpoena, the claim that the testimony may tend to incriminate the person giving it does not excuse the witness from testifying or producing the records and data, but the evidence or testimony may not be used against the person on the trial of any criminal proceeding.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.092. FEE FOR EXECUTING PROCESS. The sheriff or constable executing process shall receive the compensation authorized by the commission.

Acts 1977, 65th Leg., p. 2510, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.093. DEPOSITIONS. (a) In a matter pending for hearing before the commission or a division of the commission, the commission or an interested party may produce the testimony of a witness by written or oral deposition instead of compelling the personal attendance of the witness. For that purpose, the

commission may issue a commission or other process necessary to take a deposition.

(b) The deposition shall be taken, to the extent applicable and to the greatest extent possible, in accordance with the provisions of the Texas Rules of Civil Procedure relating to written and oral depositions.

Added by Acts 2009, 81st Leg., R.S., Ch. 85 (S.B. 1540), Sec. 3.04, eff. April 1, 2011.

SUBCHAPTER E. FEES

Sec. 81.115. APPROPRIATIONS TO COMMISSION FOR OIL AND GAS REGULATION AND CLEANUP PURPOSES. Money appropriated to the commission under the General Appropriations Act for the purposes described by Section 81.068 shall be paid from the oil and gas regulation and cleanup fund or other fund indicated by the appropriation.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 144, ch. 65, Sec. 1, eff. Sept. 1, 1981. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.03, eff. September 28, 2011.

Sec. 81.116. OIL-FIELD CLEANUP REGULATORY FEE ON OIL. (a) An oil-field cleanup regulatory fee is imposed on crude petroleum produced in this state in the amount of five-eighths of one cent on each barrel of 42 standard gallons.

(b) The fee is in addition to, and independent of any liability for, the tax imposed under Chapter 202, Tax Code.

(c) Except as provided by Subsection (d) of this section, Chapter 202, Tax Code, applies to the administration and collection of the fee, and the penalties provided by that chapter apply to any person who fails to pay or report the fee.

(d) The exemptions and reductions set out in Sections 202.052, 202.054, 202.056, 202.057, 202.059, and 202.060, Tax Code, do not affect the fee imposed by this section.

(e) Proceeds from the fee, excluding any penalties collected in connection with the fee, shall be deposited to the oil and gas regulation and cleanup fund as provided by Section 81.067.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 2, eff. Sept. 1, 1991. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 7, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 200, Sec. 17, eff. Sept. 1, 2003. Amended by: Acts 2005, 79th Leg., Ch. 267 (H.B. 2161), Sec. 1, eff. January 1, 2006; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.04, eff. September 28, 2011; Acts 2015, 84th Leg., R.S., Ch. 470 (S.B. 757), Sec. 5, eff. September 1, 2015; Acts 2019, 86th Leg., R.S., Ch. 55 (H.B. 2675), Sec. 1, eff. September 1, 2019.

Sec. 81.117. OIL-FIELD CLEANUP REGULATORY FEE ON GAS. (a) An oil-field cleanup regulatory fee is imposed on gas initially produced and saved in this state in the amount of one-fifteenth of one cent for each thousand cubic feet.

(b) The fee is in addition to, and independent of any liability for, the tax imposed under Section 201.052, Tax Code.

(c) Except as provided by Subsection (d), the administration, collection, and enforcement of the fee is the same as for the tax imposed under Section 201.052, Tax Code.

(d) The exemptions and reductions set out in Sections 201.053, 201.057, 201.058, and 202.060, Tax Code, do not affect the fee imposed by this section.

(e) Proceeds from the fee, excluding any penalties collected in connection with the fee, shall be deposited to the oil and gas regulation and cleanup fund as provided by Section 81.067.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 2, eff. Sept. 1, 1991. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 8, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 200, Sec. 18, eff. Sept. 1, 2003. Amended by: Acts 2005, 79th Leg., Ch. 267 (H.B. 2161), Sec. 2, eff. January 1, 2006; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.05, eff. September 28, 2011; Acts 2019, 86th Leg., R.S., Ch. 55 (H.B. 2675), Sec. 2, eff. September 1, 2019.

SUBCHAPTER F. CAMPAIGNING

Sec. 81.151. PENALTY FOR CAMPAIGNING. A person who receives a salary from funds provided under this title and who uses his time or a state-owned automobile for campaign purposes or for the purpose of furthering the candidacy of his employer or any other candidate for state office is guilty of a misdemeanor and on conviction shall be fined not less than $100 nor more than $500 and shall be confined in jail for not less than 30 nor more than 90 days.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.152. DISCHARGE AND INELIGIBILITY. A person found guilty under Section 81.151 of this code shall be discharged immediately from his position and shall be ineligible for employment by the state in the future.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.153. SETTING CIVIL COMPLAINT FOR HEARING. If a citizen of this state files a civil complaint with a district court in Travis County charging an employee with use of his time or a state-owned automobile for campaign purposes or to further the candidacy of his employer or any other candidate for state

office, the court shall set the complaint for hearing at a time not less than 10 nor more than 20 days after the day on which the complaint is filed.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.154. NOTICE TO EMPLOYEE. The court shall have notice of the hearing served on the employee against whom the complaint was filed at least five days before the date of the hearing.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.155. COURT'S ORDER. At the hearing, if the court determines that the employee has used his time or a state-owned automobile as charged in the complaint, the court shall certify the fact to the department, agency, or commission which employs the person and order the employee's immediate discharge.

Acts 1977, 65th Leg., p. 2511, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 81.156. APPEAL. Any person against whom charges have been filed is entitled to appeal to the court of appeals, but the pendency of the appeal does not suspend his discharge.

Acts 1977, 65th Leg., p. 2512, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 799, ch. 291, Sec. 91, eff. Sept. 1, 1981.

NATURAL RESOURCES CODE

TITLE 3. OIL AND GAS

SUBTITLE B. CONSERVATION AND REGULATION OF OIL AND GAS

CHAPTER 85. CONSERVATION OF OIL AND GAS

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 85.001. DEFINITIONS. (a) In this chapter:

(1) "Commission" means the Railroad Commission of Texas.

(2) "Pool," "common pool," "field," or "common source of supply" means a common reservoir.

(3) "Pool" means an underground reservoir containing a connected accumulation of crude petroleum oil, or natural gas, or both.

(4) "Product" and "product of oil or gas" mean a commodity or thing made or manufactured from oil or gas and derivatives or by-products of oil or gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, lubricating oil, casinghead gas, casinghead gasoline, blended gasoline, and blends or mixtures of oil, or gas, or any derivatives or by-products of them.

(b) "Oil" means crude petroleum oil, crude petroleum, and crude oil, and "gas" means natural gas. These terms shall not be construed as referring to substances different from those referred to in this chapter and other laws as "oil and gas" and these terms mean the same whether used in this chapter or in other laws relating to the conservation of oil and gas.

Acts 1977, 65th Leg., p. 2514, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.002. ANTITRUST AND MONOPOLY STATUTES. (a) The provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, Chapter 2, Acts of the 42nd Legislature, 4th Called

Session, 1932, as amended, and Chapter 76, General Laws, Acts of the 44th Legislature, Regular Session, 1935, as amended, do not affect, alter, diminish, change, or modify the antitrust and monopoly laws of this state and do not directly or indirectly authorize a violation of the antitrust and monopoly laws of this state.

(b) It is the legislative intent that no provision of this chapter that was formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, Chapter 2, Acts of the 42nd Legislature, 4th Called Session, 1932, as amended, or Chapter 76, General Laws, Acts of the 44th Legislature, Regular Session, 1935, as amended, shall affect, alter, diminish, or amend in any manner a provision of the antitrust and monopoly laws of this state or authorize a violation of the antitrust and monopoly laws. The legislative intent expressed in this subsection shall prevail and take precedence over sections cited in this subsection regardless of any statement in these sections to the contrary.

(c) If any provision of this chapter that was formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, Chapter 2, Acts of the 42nd Legislature, 4th Called Session, 1932, as amended, or Chapter 76, General Laws, Acts of the 44th Legislature, Regular Session, 1935, as amended, is construed by a court of this state in a manner that will affect, alter, diminish, or modify any provision of the antitrust and monopoly laws of this state, this provision which is in conflict is declared null and void rather than the antitrust and monopoly laws.

Acts 1977, 65th Leg., p. 2515, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER B. ADMINISTRATIVE PROVISIONS

Sec. 85.011. SUPERVISORS, DEPUTY SUPERVISORS, AND UMPIRES. The commission shall employ all supervisors, deputy supervisors,

and umpires necessary to carry out the provisions of this chapter and other related laws and rules and orders of the commission.

Acts 1977, 65th Leg., p. 2515, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.012. ASSISTANTS AND CLERICAL HELP. The commission shall employ other assistants and clerical help necessary to carry out the provisions of this chapter and other related laws and rules and orders of the commission.

Acts 1977, 65th Leg., p. 2515, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.013. PERSONS ENFORCING RULES AND ORDERS. A person entrusted with the enforcement of the rules and orders of the commission shall be a regular employee of the state and paid by the state. No person other than a regular employee of the state may be charged with or relied on for the performance of these duties.

Acts 1977, 65th Leg., p. 2516, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER C. PROVISIONS GENERALLY APPLICABLE TO THE CONSERVATION OF OIL AND GAS

Sec. 85.041. ACTS PROHIBITED IN VIOLATION OF LAWS, RULES, AND ORDERS. (a) The purchase, acquisition, or sale, or the transporting, refining, processing, or handling in any other way, of oil or gas, produced in whole or in part in violation of any oil or gas conservation statute of this state or of any rule or order of the commission under such a statute, is prohibited.

(b) The purchase, acquisition, or sale, or the transporting, refining, processing, or handling in any other

way, of any product of oil or gas which is derived in whole or in part from oil or gas or any product of either, which was in whole or part produced, purchased, acquired, sold, transported, refined, processed, or handled in any other way, in violation of any oil or gas conservation statute of this state, or of any rule or order of the commission under such a statute, is prohibited.

Acts 1977, 65th Leg., p. 2516, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.042. RULES AND ORDERS. (a) The commission may promulgate and enforce rules and orders necessary to carry into effect the provisions of Section 85.041 of this code and to prevent that section's violation.

(b) When necessary, the commission shall 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.

Acts 1977, 65th Leg., p. 2516, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.043. APPLICATION OF CERTAIN RULES AND ORDERS. If the commission requires a showing that refined products were manufactured from oil legally produced, the requirement shall be of uniform application throughout the state; provided that, if the rule or order is promulgated for the purpose of controlling a condition in any local area or preventing a violation in any local area, then on the complaint of a person that the same or similar conditions exist in some other local area and the promulgation and enforcement of the rule could be beneficially applied to that additional area, the commission may determine whether or not those conditions do exist, and if it is shown that they do, the rule or order may be enlarged to include the additional area.

Acts 1977, 65th Leg., p. 2516, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by: Acts 2005, 79th Leg., Ch. 346 (S.B. 1175), Sec. 1, eff. June 17, 2005.

Sec. 85.045. WASTE ILLEGAL AND PROHIBITED. The production, storage, or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited.

Acts 1977, 65th Leg., p. 2517, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.046. WASTE. (a) The term "waste," among other things, specifically includes:

(1) operation of any oil well or wells with an inefficient gas-oil ratio and the commission may determine and prescribe by order the permitted gas-oil ratio for the operation of oil wells;

(2) drowning with water a stratum or part of a stratum that is capable of producing oil or gas or both in paying quantities;

(3) underground waste or loss, however caused and whether or not the cause of the underground waste or loss is defined in this section;

(4) permitting any natural gas well to burn wastefully;

(5) creation of unnecessary fire hazards;

(6) physical waste or loss incident to or resulting from drilling, equipping, locating, spacing, or operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas from any pool;

(7) waste or loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool; however, it is not the intent of this section

or the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, to require repressuring of an oil pool or to require that the separately owned properties in any pool be unitized under one management, control, or ownership;

(8) surface waste or surface loss, including the temporary or permanent storage of oil or the placing of any product of oil in open pits or earthen storage, and other forms of surface waste or surface loss including unnecessary or excessive surface losses, or destruction without beneficial use, either of oil or gas;

(9) escape of gas into the open air in excess of the amount necessary in the efficient drilling or operation of the well from a well producing both oil and gas;

(10) production of oil in excess of transportation or market facilities or reasonable market demand, and the commission may determine when excess production exists or is imminent and ascertain the reasonable market demand; and

(11) surface or subsurface waste of hydrocarbons, including the physical or economic waste or loss of hydrocarbons in the creation, operation, maintenance, or abandonment of an underground hydrocarbon storage facility.

(b) Notwithstanding the provisions contained in this section or elsewhere in this code or in other statutes or laws, the commission may permit production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas where the commission, after notice and opportunity for hearing, has found that producing oil or gas or oil and gas in a commingled state will prevent waste, promote conservation, or protect correlative rights.

(c) The commission, after notice and opportunity for hearing, may permit surface commingling of production of oil or gas or oil and gas from two or more tracts of land producing from the same reservoir or from one or more tracts of land producing from different reservoirs if the commission finds that

the commingling will prevent waste, promote conservation, or protect correlative rights. The commission may permit the commingling regardless of whether the tracts or commission-designated reservoirs have the same working or royalty interest ownership. The amount of production attributable to each tract or commission-designated reservoir shall be determined in a manner consistent with this title. The commission has broad discretion in administering this subsection and shall adopt and enforce rules or orders as necessary to administer this subsection.

Acts 1977, 65th Leg., p. 2517, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1979, 66th Leg., p. 673, ch. 300, Sec. 1, eff. May 29, 1979; Acts 1981, 67th Leg., p. 3166, ch. 830, Sec. 2, eff. June 17, 1981; Acts 1995, 74th Leg., ch. 870, Sec. 1, eff. Sept. 1, 1995; Acts 1995, 74th Leg., ch. 871, Sec. 1, eff. Sept. 1, 1995.

Sec. 85.047. EXCLUSION FROM DEFINITION OF WASTE. The use of gas produced from an oil well within the permitted gas-oil ratio for manufacture of natural gasoline shall not be included in the definition of waste.

Acts 1977, 65th Leg., p. 2517, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.048. AUTHORITY TO LIMIT PRODUCTION. (a) Under the provisions of Subsection (10), Section 85.046 of this code, the commission shall not restrict the production of oil from any new field brought into production by exploration until the total production from that field is 10,000 barrels of oil a day in the aggregate.

(b) The commission's authority to restrict production from a new field under other provisions of Section 85.046 of this code is not limited by this section.

Acts 1977, 65th Leg., p. 2517, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.049. HEARING. (a) On verified complaint of any person interested in the subject matter that waste of oil or gas is taking place in this state or is reasonably imminent, or on its own initiative, the commission, after proper notice, may hold a hearing to determine whether or not waste is taking place or is reasonably imminent and if any rule or order should be adopted or if any other action should be taken to correct, prevent, or lessen the waste.

(b) The hearing shall be held at the time and place determined by the commission.

Acts 1977, 65th Leg., p. 2517, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.050. PROCEDURE AT HEARING. (a) At the hearing, interested parties shall be entitled to be heard and to introduce evidence and require the attendance of witnesses.

(b) The production of evidence may be required as provided by law.

Acts 1977, 65th Leg., p. 2518, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.051. ADOPTION OF RULE OR ORDER. If the commission finds at the hearing that waste is taking place or is reasonably imminent, it shall adopt a rule or order in the manner provided by law as it considers reasonably required to correct, prevent, or lessen the waste.

Acts 1977, 65th Leg., p. 2518, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.052. COMPLIANCE WITH RULE OR ORDER. From and after the promulgation of a rule or order of the commission, it is the duty of each person affected by the rule or order to comply with it.

Acts 1977, 65th Leg., p. 2518, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.053. DISTRIBUTION, PRORATION, AND APPORTIONMENT OF ALLOWABLE PRODUCTION. (a) If a rule or order of the commission limits or fixes in a pool or portion of a pool the production of oil, or the production of gas from wells producing gas only, the commission, on written complaint by an affected party or on its own initiative and after notice and an opportunity for a hearing, shall distribute, prorate, or otherwise apportion or allocate the allowable production among the various producers on a reasonable basis if the commission finds that action to be necessary to:

(1) prevent waste; or

(2) adjust the correlative rights and opportunities of each owner of oil or gas in a common reservoir to produce and use or sell the oil or gas as permitted in this chapter.

(b) When, as provided in Subsection (b) of Section 85.046 or Subsection (b) of Section 86.012 of this code, as amended, the commission has permitted production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas, the commission may distribute, prorate, apportion, or allocate the production of such commingled separate multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas as if they were a single pool; provided, however, that:

(i) such commingling shall not cause the allocation of allowable production from a well producing from any separate accumulation or accumulations to be less than that which would result from the commission applying the provisions of Section 86.095 of this code to such accumulation or accumulations; and

(ii) the allocation of the allowable for such commingled production shall be based on not less than two factors which the Railroad Commission shall take into account as directed by Section 86.089 of this code.

Acts 1977, 65th Leg., p. 2518, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 2578, ch. 688, Sec. 1, eff. June 16, 1981; Acts 1995, 74th Leg., ch. 435, Sec. 1, eff. Aug. 28, 1995. Amended by: Acts 2005, 79th Leg., Ch. 346 (S.B. 1175), Sec. 2, eff. June 17, 2005.

Sec. 85.057. RESTRICTION ON UNEXPLORED TERRITORY. The provisions of this chapter that were formerly a part of Chapter 2, Acts of the 42nd Legislature, 4th Called Session, 1932, as amended, shall not be construed to grant the commission any authority to restrict or in any manner limit the drilling of wells to explore for oil or gas or both in territory that is not known to produce either oil or gas.

Acts 1977, 65th Leg., p. 2519, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.058. COMMISSION INQUIRY AND DETERMINATION. From time to time, the commission may inquire into the production, storage, transportation, refining, reclaiming, treating, marketing, and processing of oil and gas, and the reasonable market demand for oil and gas, so that it may determine whether or not waste exists or is imminent or whether the oil and gas conservation laws of this state or the rules and orders of the commission promulgated under those laws are being violated.

Acts 1977, 65th Leg., p. 2519, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by: Acts 2005, 79th Leg., Ch. 346 (S.B. 1175), Sec. 5, eff. June 17, 2005.

Sec. 85.059. RECORDS. Each person who produces, stores, transports, refines, reclaims, treats, markets, or processes oil or gas or the products of either shall keep in this state accurate records of the amount of oil or gas which such person produced, stored, transported, refined, reclaimed, treated, marketed, or processed and of the source from which the person produced, obtained, or received the oil or gas or the products of either and the disposition made of them.

Acts 1977, 65th Leg., p. 2519, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.060. SWORN STATEMENTS AND REPORTS. The commission may require a person who produces, stores, transports, refines, reclaims, treats, markets, or processes oil or gas or the products of either to make and file with the commission sworn statements or reports as to facts within his knowledge or possession pertaining to the reasonable market demand for oil and to the production, storage, transportation, refining, reclaiming, treating, marketing, or processing of oil or gas and the products of either. The report shall include those facts enumerated in Section 85.059 of this code.

Acts 1977, 65th Leg., p. 2519, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.061. INSPECTION AND GAUGING. The commission may require any well, lease, refinery, plant, tank or storage, pipeline, or gathering line that belongs to or is under the control of a person who produces, stores, transports, refines, reclaims, treats, markets, or processes oil or gas or the products of either to be inspected or gauged by the agents of the commission whenever and as often as and for such periods as the commission considers necessary.

Acts 1977, 65th Leg., p. 2519, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.062. EXAMINATION OF BOOKS AND RECORDS. The commission and its agents and the attorney general and his assistants and representatives may examine the books and records of a person who produces, stores, transports, refines, reclaims, treats, markets, or processes oil or gas or the products of either as often as considered necessary for the purpose of determining the facts concerning matters covered by Sections 85.058 through 85.061 of this code.

Acts 1977, 65th Leg., p. 2520, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.063. VIOLATIONS BY CORPORATIONS. (a) The failure of a corporation chartered under the laws of this state to comply with the provisions of Sections 85.059 through 85.062 of this code and to keep the records required by Section 85.059 of this code in this state or the refusal to permit officers designated in Section 85.062 of this code to inspect and examine the records required by Section 85.059 of this code shall constitute grounds for forfeiture of the corporation's charter rights and privileges and dissolution of its corporate existence.

(b) The failure of a foreign corporation to comply with the provisions of Sections 85.059 through 85.062 of this code and to keep the records required by Section 85.059 of this code in this state or the refusal to permit officers designated in Section 85.062 of this code to inspect and examine the records required by Section 85.059 of this code shall be grounds for enjoining and forever prohibiting such corporation from doing business in this state.

Acts 1977, 65th Leg., p. 2520, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.064. ACTION AGAINST CORPORATION. (a) If he determines that the public interest requires it, the attorney general shall institute suit or other appropriate action in Travis County for forfeiture of charter rights of a domestic corporation or to enjoin a foreign corporation from doing business in this state when a corporation is deemed guilty of violating the provisions of Sections 85.059 through 85.062 of this code. The attorney general may take this action on his own motion and without leave or order of any judge or court.

(b) On judgment against a defendant for violating the provisions of Sections 85.059 through 85.062 of this code, the court may, if in its judgment the public interest requires it, forfeit the charter rights of a defendant domestic corporation or enjoin a defendant foreign corporation from doing business in this state.

Acts 1977, 65th Leg., p. 2520, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.065. INFORMAL COMPLAINT PROCESS REGARDING LOSS OF OR INABILITY TO ACCOUNT FOR NATURAL GAS GATHERED OR TRANSPORTED. (a) A producer may submit a written request to a person who gathers or transports gas for the producer for an explanation of any loss of or inability to account for the gas tendered to the person by the producer. The request may ask the person to provide any or all of the information that would be required to be included in an accounting under Subsection (c). Not later than the 30th day after the date the person receives the request from the producer, the person must provide the producer a written explanation of any loss of or inability to account for the gas tendered to the person by the producer. The response must include any relevant information requested by the producer that is available to the person and that would be required to be included in an accounting under Subsection (c).

(b) If a producer submits a request under Subsection (a) to a person who gathers or transports gas for the producer and the person provides an inadequate explanation of any loss of or inability to account for the gas, or fails to provide any explanation of any loss of or inability to account for the gas by the deadline provided by that subsection, the producer may file with the commission an informal complaint against the person. An informal complaint may not be filed before the 30th day after the end of the production period covered by the complaint. An informal complaint must:

(1) specify the production period covered by the complaint;

(2) state that at least 30 days have elapsed since the end of the production period covered by the complaint; and

(3) if the producer metered the volume of gas tendered to the person who gathered or transported the gas:

(A) describe the type of meter used; and

(B) state the date the meter was last calibrated.

(c) Not later than the 14th day after the date the complaint is filed, the person who gathered or transported the gas shall provide to the producer and the commission an accounting of the gas tendered to the person by the producer for gathering or transport during the production period covered by the complaint. The accounting may be provided on a thousand cubic feet or a million British thermal unit basis, as applicable, and must include the information the commission determines to be necessary to resolve an informal complaint under this section, which may include:

(1) the amount of gas tendered by the producer from each well that has a meter;

(2) a laboratory analysis of the composition and heating value of the gas and other substances tendered by the producer, if such an analysis has been performed;

(3) if available, a schematic drawing of the person's system for gathering or transporting gas that shows:

(A) each meter type;

(B) the date each meter was last calibrated;

(C) the accuracy of each meter; and

(D) all equipment that alters, disposes of, or otherwise consumes any of the gas tendered to the person;

(4) the estimated amount of gas used for fuel, flared, or vented for construction, repair, maintenance, or other operational uses and, if the information is available, the location of that use;

(5) the estimated amount of contaminants or other impurities removed from the gas and the location at which the impurities were removed;

(6) the estimated amount of liquid hydrocarbons and condensate removed from the gas and the location at which the liquid hydrocarbons and condensate were removed;

(7) the estimated amount of gas lost and the location at which the gas was lost;

(8) the estimated amount of gas redelivered by the person, including the amount of gas sold that was allocated to the producer, and the location at which the redelivery of the gas occurred;

(9) any amount of gas received from the producer by the person that remains unaccounted for; and

(10) any other information the person who gathered or transported the gas considers relevant to the resolution of the complaint.

(d) The commission may grant an extension of time to the person who gathered or transported the gas to provide the accounting required by Subsection (c). An extension may not permit the accounting to be provided later than the 45th day after the date the informal complaint was filed.

(e) If the person who gathered or transported the gas does not have the information necessary to provide the accounting required by Subsection (c), the person must provide to the producer and to the commission a written explanation of the reason the person does not have the information.

(f) If the person who gathered or transported the gas fails to provide the accounting required by Subsection (c) or the explanation required by Subsection (e), the informal complaint filed by the producer is considered to be valid.

(g) If Subsection (f) applies or the commission determines that the person who gathered or transported the gas committed waste, the commission may take any action it considers appropriate, including issuing an order in a formal proceeding to prevent waste by the person who gathered or transported the gas.

(h) This subsection applies only to a producer and a person who gathers or transports gas for the producer under a contract between the producer and that person that is entered into or renewed on or after September 1, 2007. On written request, the producer is entitled to audit the books and records of the person that pertain to the contract between the producer and the person for the purpose of verifying whether any gas tendered to the person by the producer that the person has lost or is unable to account for has been allocated to the volume of gas tendered to the person by the producer as required by the contract. A producer is not entitled to conduct an audit under this subsection more frequently than annually.

Added by Acts 2007, 80th Leg., R.S., Ch. 696 (H.B. 1920), Sec. 1, eff. September 1, 2007.

SUBCHAPTER D. MARGINAL WELLS

SUBCHAPTER F. RULES AND ORDERS OF THE COMMISSION

Sec. 85.201. ADOPTION OF RULES AND ORDERS. The commission shall make and enforce rules and orders for the conservation of oil and gas and prevention of waste of oil and gas.

Acts 1977, 65th Leg., p. 2522, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.202. PURPOSES OF RULES AND ORDERS. (a) The rules and orders of the commission shall include rules and orders:

(1) to prevent waste, as defined in Section 85.046 of this code, of oil and gas in drilling and producing operations and in the storage, piping, and distribution of oil and gas;

(2) to require dry or abandoned wells to be plugged in a manner that will confine oil, gas, and water in the strata in which they are found and prevent them from escaping into other strata;

(3) for the drilling of wells and preserving a record of the drilling of wells;

(4) to require wells to be drilled and operated in a manner that will prevent injury to adjoining property;

(5) to prevent oil and gas and water from escaping from the strata in which they are found into other strata;

(6) to provide rules for shooting wells and for separating oil from gas;

(7) to require records to be kept and reports made; and

(8) to provide for issuance of permits, tenders, and other evidences of permission when the issuance of the permits, tenders, or permission is necessary or incident to the enforcement of the commission's rules or orders for the prevention of waste.

(b) The commission shall do all things necessary for the conservation of oil and gas and prevention of waste of oil and gas and may adopt other rules and orders as may be necessary for those purposes.

Acts 1977, 65th Leg., p. 2522, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.2021. DRILLING PERMIT FEE. (a) With each application or materially amended application for a permit to

drill, deepen, plug back, or reenter a well, the applicant shall submit to the commission a nonrefundable fee of:

(1) $200 if the total depth of the well is 2,000 feet or less;

(2) $225 if the total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(3) $250 if the total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet;

(4) $300 if the total depth of the well is greater than 9,000 feet.

(b) An applicant shall submit an additional nonrefundable fee of $200 when a Rule 37 spacing or a Rule 38 density exception review is requested.

(c) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(d) All fees collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 1983, 68th Leg., p. 5260, ch. 967, Sec. 7, eff. Sept. 1, 1983. Amended by Acts 1985, 69th Leg., ch. 239, Sec. 74, eff. Sept. 1, 1985; Acts 1991, 72nd Leg., ch. 603, Sec. 5, eff. Sept. 1, 1991; Acts 1999, 76th Leg., ch. 1089, Sec. 2, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 9, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1233, Sec. 10, eff. Sept. 1, 2004. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.06, eff. September 28, 2011.

Sec. 85.203. CONSIDERATIONS IN ADOPTING RULES AND ORDERS TO PREVENT WASTE. The commission may consider any or all of the definitions of waste stated in Section 85.046 of this code, whenever the facts, circumstances, or conditions make them applicable, in adopting rules or orders to prevent waste of oil or gas.

Acts 1977, 65th Leg., p. 2523, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.204. PROHIBITED RULES AND ORDERS. The commission is not authorized to adopt a rule or order or to make a determination or holding that any mode, manner, or process of refining oil constitutes waste.

Acts 1977, 65th Leg., p. 2523, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.205. NOTICE AND HEARING. No rule or order pertaining to the conservation of oil and gas or to the prevention of waste of oil and gas may be adopted by the commission except after notice and hearing as provided by law.

Acts 1977, 65th Leg., p. 2523, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.206. EMERGENCY ORDER. (a) If the commission finds an emergency to exist, that in the commission's judgment requires the adoption of an order without giving notice or holding a hearing, the emergency order may be adopted and shall be valid as though notice had been given and a hearing held.

(b) The emergency order shall remain in force no longer than 15 days from its effective date.

(c) The emergency order shall expire, in any event, at the time an order relating to the same subject matter and adopted after proper notice and hearing becomes effective.

Acts 1977, 65th Leg., p. 2523, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.207. EFFECT OF AMENDMENT, REPEAL, OR EXPIRATION OF A RULE OR ORDER. The amendment, repeal, or expiration of a rule or order of the commission adopted under the provisions of this

chapter that were formerly a part of Chapter 76, General Laws, Acts of the 44th Legislature, Regular Session, 1935, as amended, or the provisions of Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, shall not have the effect of releasing or discharging from liability, penalty, or forfeiture any person violating the rule or order before the effective date of the amendment, repeal, or expiration. Prosecutions and suits for these violations, liabilities, penalties, and forfeitures shall be instituted and proceeded with in all respects as if the rule or order had not been amended or repealed, or had not expired.

Acts 1977, 65th Leg., p. 2523, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER G. SUITS CHALLENGING THE VALIDITY OF LAWS AND ORDERS

Sec. 85.241. SUITS BY INTERESTED PERSONS. Any interested person who is affected by the conservation laws of this state or orders of the commission relating to oil or gas and the waste of oil or gas, and who is dissatisfied with any of these laws or orders, may file suit against the commission or its members in a court of competent jurisdiction in Travis County to test the validity of the law or order.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.242. EXPEDITIOUS TRIAL. A suit brought under Section 85.241 of this code shall be advanced for trial and shall be determined as expeditiously as possible. No postponement or continuance shall be granted except for reasons considered imperative by the court.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.243. BURDEN OF PROOF. In the trial of a suit brought under Section 85.241 of this code, the burden of proof shall be on the party complaining of the law or order, and the law or order is deemed prima facie valid.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.244. CONDITIONS FOR INJUNCTIVE RELIEF. No temporary restraining order, temporary or permanent injunction, or other form of injunctive relief may be granted against the commission, its members, agents, and representatives to restrain it or them from enforcing any rule or order adopted by the commission under the oil and gas conservation laws of this state or from enforcing any of these laws unless notice is given to the commission and a hearing is held as provided in this subchapter.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.245. NOTICE TO COMMISSION. (a) At the time a petition or application is filed requesting a temporary restraining order or any form of temporary injunctive relief, the clerk of the court in which the petition or application is filed shall issue notice in writing to the commission.

(b) The notice shall include:

(1) the docket number;

(2) the style of the case; and

(3) a brief statement of the nature of the suit.

(c) The notice shall be served on the commission in Travis County by delivering a copy of the citation to the commission, a member of the commission, or the secretary of the commission for the service of other citations.

(d) Five days after the citation has been served a hearing may be held on the petition or application.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.246. INTERVENTION IN SUIT. In the discretion of the court, any person who is interested in the subject matter of the suit may intervene.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.247. RULES AND ORDERS PRIMA FACIE VALID. The rule or order complained of in the suit is prima facie valid, and the use and introduction of the verified petition of the plaintiff shall not be sufficient to overcome the prima facie validity of the rule or order or to authorize the court to grant any injunctive relief against the enforcement of the rule or order.

Acts 1977, 65th Leg., p. 2524, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.248. BOND. Before an order granting injunctive relief against an oil and gas conservation law, rule, or order of the commission becomes effective, the plaintiff shall be required by the court to execute a bond with good and sufficient sureties in a reasonably sufficient amount determined by the court to indemnify any persons whom the court may find from the facts proven will suffer damage as a result of the violation of the law, rule, or order in question. The persons shall be named in the order of the judge at the time the amount of the bond is fixed by the court and entered in the record.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.249. CONDITIONS OF BOND. (a) In determining the amount of the bond, the judge shall consider all facts and circumstances surrounding the parties and the ability of the plaintiff to make the bond so that the judge can determine the amount and reasonableness of the bond under the facts and circumstances.

(b) A bond made or executed by a bonding or surety company shall be by a company authorized to do business in Texas.

(c) The bond shall be approved by the judge and shall be for the use and benefit of and may be sued on by any person named in the order who suffers damage as a result of violation of the law, rule, or order.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.250. CHANGING AMOUNT, PARTIES, AND SURETIES. On a motion and for good cause shown, and after notice to the parties, the court periodically may:

(1) increase or decrease the amount of the bond;

(2) add new beneficiaries; and

(3) require new and additional sureties that the facts may justify.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.251. SUITS ON BONDS. A suit on a bond must be instituted within six months from the date of the final determination of the validity in whole or in part of the rule or order.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.252. INADMISSIBLE EVIDENCE. A finding by the court that any party is likely to suffer damage is not admissible as evidence of damages in a suit on the bond.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.253. APPEAL. After notice and hearing on an application for injunctive relief, either party to the suit is entitled to appeal the judgment or order granting or refusing the temporary restraining order, temporary or permanent injunction, or other form of injunctive relief or granting or overruling a motion to dissolve the temporary restraining order, temporary or permanent injunction, or other form of injunctive relief.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.254. APPEAL HAS PRECEDENCE. The appeal is returnable at once to the appellate court and the action appealed shall have precedence in the appellate court over all cases, proceedings, and causes of a different character that are pending.

Acts 1977, 65th Leg., p. 2525, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.255. EARLY DECISION BY COURT OF APPEALS. The court of appeals shall decide the question in the appeal at as early a date as possible.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 800, ch. 291, Sec. 92, eff. Sept. 1, 1981.

Sec. 85.256. APPEAL PROCEDURES. The provisions and requirements of Article 4662, Revised Civil Statutes of Texas, 1925, as amended, and Rule 385 of the Texas Rules of Civil Procedure, as amended, relating to temporary injunctions, apply to appeals from any order granting or refusing a temporary restraining order, or granting or overruling a motion to dissolve a temporary restraining order under the provisions of this subchapter.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.257. CERTIFIED QUESTIONS AND WRITS OF ERROR. (a) If a question is certified or writ of error requested or granted to the supreme court, the supreme court shall set the cause for hearing immediately and shall decide the cause at as early a date as possible.

(b) The cause shall have precedence over all other causes, proceedings, and causes of a different character in the court.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.258. AUTHORITY OF COURT OF APPEALS TO ISSUE WRITS. The court of appeals and its judges have the jurisdiction to issue writs of prohibition, mandamus, and injunction to prevent the enforcement of any order or judgment of a trial court or judge who grants any type of injunctive relief without notice and hearing in violation of the requirements of Sections 85.244 and 85.245 of this code.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 800, ch. 291, Sec. 93, eff. Sept. 1, 1981.

Sec. 85.259. ISSUANCE OF WRITS BY COURT OF APPEALS. If it appears that the provisions of Sections 85.244 and 85.245 of this code have not been complied with, then on proper application from the commission to the court of appeals having jurisdiction, the court shall issue instanter the necessary writs of prohibition, mandamus, or injunction to prohibit and restrain the trial judge from enforcing or attempting to enforce the provisions of the injunction issued by him and to prohibit and restrain the party or parties in whose favor the order is entered from acting or attempting to act under the protection of the order or from violating the law, rule, or order of the commission attacked.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1981, 67th Leg., p. 800, ch. 291, Sec. 94, eff. Sept. 1, 1981.

SUBCHAPTER H. RECEIVERSHIP

Sec. 85.291. REQUEST FOR RECEIVER. If a rule or order of the commission has been finally adjudicated to be valid in whole or part in a suit to which the commission is a party, and if after that time a party to the suit or other proceedings in which the rule or order was declared valid violates the rule, order, or judgment or shall thereafter use or permit to be used any property owned or controlled by him in violation of the rule, order, or judgment, the commission shall make application to the judge of the trial court setting out the rule, order, or judgment and stating that the party subsequent to the date of the judgment violated or is violating the rule, order, or judgment and requesting that a receiver be appointed as provided in this subchapter.

Acts 1977, 65th Leg., p. 2526, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.292. APPOINTMENT OF RECEIVER AND BOND. After an application is submitted as provided in Section 85.291 of this code, the judge of the trial court, after notice and hearing, may appoint a receiver of the property involved or used in violation of the rule, order, or judgment and shall set a proper bond for the receiver.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.293. DUTIES OF RECEIVER. As soon as the receiver is qualified, he shall take possession of the property and shall perform his duties as receiver of the property under the orders of the court, strictly observing the rule, order, or judgment.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.294. DISSOLUTION OF RECEIVERSHIP. A party whose property is placed in receivership may move to dissolve the receivership and to discharge the receiver on the terms the court may prescribe.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER I. DAMAGES

Sec. 85.321. SUIT FOR DAMAGES. A party who owns an interest in property or production that may be damaged by another party violating the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, or another law of this state prohibiting waste or a valid rule or order of the commission may sue for and recover damages and have any other relief to which he may be entitled at law or in equity. Provided, however, that

in any action brought under this section or otherwise, alleging waste to have been caused by an act or omission of a lease owner or operator, it shall be a defense that the lease owner or operator was acting as a reasonably prudent operator would act under the same or similar facts and circumstances.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1987, 70th Leg., ch. 1071, Sec. 1, eff. Aug. 31, 1987.

Sec. 85.322. PROCEEDINGS NOT TO IMPAIR SUIT FOR DAMAGES. None of the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, no suit by or against the commission, and no penalties imposed on or claimed against any party violating a law, rule, or order of the commission shall impair or abridge or delay a cause of action for damages or other relief that an owner of land or a producer of oil or gas, or any other party at interest, may have or assert against any party violating any rule or order of the commission or any judgment under this chapter.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER J. INJUNCTIONS

Sec. 85.351. SUIT FOR INJUNCTION. (a) If it appears that a person is violating or threatening to violate the provisions of this chapter that were formerly a part of Chapter 76, General Laws, Acts of the 44th Legislature, Regular Session, 1935, as amended, or Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, or any rule or order of the commission adopted under those laws, the commission, through the attorney general, shall

bring suit in the name of the state to restrain the violation or threatened violation.

(b) The suit shall be brought against the person violating or threatening to violate the law, rule, or order in a court of competent jurisdiction in Travis County, in the county in which the violation occurred, or in the county of residence of any defendant.

Acts 1977, 65th Leg., p. 2527, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5255, ch. 967, Sec. 2, eff. Sept. 1, 1983.

Sec. 85.352. TYPES OF COURT ORDERS. In the suit, the commission in the name of the state may obtain prohibitory and mandatory injunctions, including temporary restraining orders and temporary injunctions, that the facts may warrant.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.353. APPOINTMENT OF RECEIVER. (a) The violation by a person of any injunction granted under the provisions of this subchapter shall be sufficient grounds for appointment by the court of a receiver to take charge of the person's property and to exercise authority that in the judgment of the court is necessary to bring about compliance with the injunction. The court may appoint the receiver either on its own motion or on motion of the commission in the name of the state.

(b) No receiver may be appointed until after notice is given and a hearing is held.

(c) The authority to appoint a receiver is in addition to and cumulative of the authority to punish for contempt.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER K. PENALTIES, IMPRISONMENT, AND CONFINEMENT

Sec. 85.381. PENALTY FOR VIOLATION OF LAWS, RULES, AND ORDERS. (a) In addition to being subject to any forfeiture provided by law and to any penalty imposed by the commission for contempt for violation of its rules or orders, any person who violates the provisions of Sections 85.045 and 85.046 of this code, Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, or any rule or order of the commission promulgated under those laws is subject to a penalty of not more than:

(1) $10,000 when the provision, rule, or order pertains to safety or the prevention or control of pollution; or

(2) $1,000 when the provision, rule, or order does not pertain to safety or the prevention or control of pollution.

(b) The applicable maximum penalty may be assessed for each and every day of violation and for each and every act of violation.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983.

Sec. 85.382. VENUE. The penalty provided in Section 85.381 of this code shall be recovered in a court of competent jurisdiction in Travis County, in the county in which the violation occurred, or in the county of the residence of any defendant.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983.

Sec. 85.383. SUIT. By direction of the commission, the suit to recover the penalty shall be instituted and conducted in

the name of the state by the attorney general or by the county or district attorney in the county in which the suit is brought.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.384. EFFECT OF RECOVERY OR PAYMENT OF PENALTY. The recovery or payment of the penalty shall not authorize the violation of any provision of Section 85.045 or 85.046 of this code, Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, or any rule or order of the commission adopted under those laws.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.385. PERSONS AIDING OR ABETTING VIOLATION. Any person who aids or abets any other person in violating Section 85.045 or 85.046 of this code, Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, or any rule or order adopted by the commission under those laws is subject to the same penalties as provided in Section 85.381 of this code.

Acts 1977, 65th Leg., p. 2529, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.3855. ADMINISTRATIVE PENALTY. (a) The commission may impose an administrative penalty on a person who:

(1) violates Section 91.705 or 91.706 or a rule or order adopted under Section 91.705 or 91.706; or

(2) knowingly destroys, breaks, removes, or otherwise tampers with, or attempts to destroy, break, remove, or otherwise tamper with, a cap, seal, or other device placed by

the commission on an oil well, gas well, oil and gas well, or other associated oil or gas gathering equipment.

(b) The amount of the penalty may not exceed $10,000 for each violation. The amount shall be based on:

(1) the seriousness of the violation, including the nature, circumstances, extent, and gravity of the violation;

(2) the economic harm to property or the environment caused by the violation;

(3) the history of previous violations;

(4) efforts to correct the violation; and

(5) any other matter that justice may require.

(c) The enforcement of the penalty may be stayed during the time the order is under judicial review if the person pays the penalty to the clerk of the court or files a supersedeas bond with the court in the amount of the penalty. A person who cannot afford to pay the penalty or file the bond may stay the enforcement by filing an affidavit in the manner required by the Texas Rules of Civil Procedure for a party who cannot afford to file security for costs, subject to the right of the commission to contest the affidavit as provided by those rules.

(d) The attorney general may sue to collect the penalty.

(e) A proceeding to impose the penalty is considered to be a contested case under Chapter 2001, Government Code.

(f) A penalty imposed under this section is in addition to a forfeiture provided by law or a penalty imposed by the commission for contempt for violation of a commission rule or order.

Added by Acts 1999, 76th Leg., ch. 1252, Sec. 1, eff. Sept. 1, 1999. Amended by: Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 2, eff. September 1, 2007.

Sec. 85.386. FORGING NAMES ON PERMITS AND TENDERS. A person shall be imprisoned in the Texas Department of Criminal Justice for not less than two nor more than five years if he:

(1) forges the name of an agent, officer, or employee of the commission to a permit or tender of the commission relating to oil or gas or any product or by-product of oil or gas;

(2) forges the name of any person to such a tender or permit; or

(3) knowingly uses a forged instrument to induce another to handle or transport oil or gas or any product or by-product of oil or gas.

Acts 1977, 65th Leg., p. 2529, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by: Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 25.133, eff. September 1, 2009.

Sec. 85.387. PROCURING TENDERS AND PERMITS. A person shall be imprisoned in the Texas Department of Criminal Justice for not less than two nor more than five years if he:

(1) knowingly procures or causes an agent, officer, or employee of the commission to approve or issue a permit or tender of the commission relating to oil or gas or any product or by-product of oil or gas that includes a statement or representation that is false and that materially misrepresents the true facts respecting the oil or gas or any product or by-product of either; or

(2) procures or causes an agent, officer, or employee of the commission to issue to him a permit or tender relating to oil or gas or any product or by-product of either with the intent to defraud.

Acts 1977, 65th Leg., p. 2529, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by: Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 25.134, eff. September 1, 2009.

Sec. 85.388. POSSESSING A FORGED PERMIT OR TENDER. Any person who knowingly has in his possession a forged tender or permit of the commission relating to oil or gas or any product

or by-product of oil or gas for the purpose of transporting, handling, or selling oil or gas shall be guilty of a misdemeanor and on conviction shall be fined not less than $25 nor more than $1,000 or shall be confined in the county jail for not less than 30 days nor more than one year, or both.

Acts 1977, 65th Leg., p. 2529, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 85.389. CRIMINAL PENALTY. (a) A person who is not the owner or operator of an oil well, gas well, or oil and gas well, a purchaser under contract of oil, gas, or oil and gas from a well, a gatherer with written authorization from the owner, operator, or purchaser, or an authorized representative of the commission who knowingly destroys, breaks, removes, or otherwise tampers with or attempts to destroy, break, remove, or otherwise tamper with any cap, seal, or other device placed on an oil well, gas well, oil and gas well, or associated oil or gas gathering equipment by the owner or operator for the purpose of controlling or limiting the operation of the well or associated equipment commits an offense.

(b) An offense under this section is a felony of the third degree.

Added by Acts 1983, 68th Leg., p. 5230, ch. 960, Sec. 1, eff. Sept. 1, 1983.

NATURAL RESOURCES CODE

TITLE 3. OIL AND GAS

SUBTITLE B. CONSERVATION AND REGULATION OF OIL AND GAS

CHAPTER 89. ABANDONED WELLS

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 89.001. POLICY. The conservation and development of all the natural resources of this state are declared to be a public right and duty. It is also declared that the protection of water and land of the state against pollution or the escape of oil or gas is in the public interest. In the exercise of the police power of the state, it is necessary and desirable to provide additional means so that wells that are drilled for the exploration, development, or production of oil or gas, or as injection or salt water disposal wells, and that have been abandoned and are leaking salt water, oil, gas, or other deleterious substances into freshwater formations or on the surface of the land, may be plugged, replugged, or repaired by or under the authority and direction of the commission.

Acts 1977, 65th Leg., p. 2552, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 89.002. DEFINITIONS. (a) In this chapter:

(1) "Well" means a hole drilled for the purpose of:

(A) producing oil or gas;

(B) injecting fluid or gas in the ground in connection with the exploration or production of oil and gas;

(C) obtaining geological information by taking cores or through seismic operations; or

(D) producing geothermal energy and associated resources that are subject to the jurisdiction of the Railroad Commission of Texas.

(2) "Operator" means a person who assumes responsibility for the physical operation and control of a well as shown by a form the person files with the commission and the commission approves. The commission may not require a person to assume responsibility for a well as a condition to being permitted to assume responsibility for another well. In the event of a sale or conveyance of an unplugged well or the right to operate an unplugged well, a person ceases being the operator for the purpose of Section 89.011 only if the well was in

compliance with commission rules relating to safety or the prevention or control of pollution at the time of sale or conveyance and once the person who acquires the well or right to operate the well:

(A) specifically identifies the well as a well for which the person assumes plugging responsibility on forms required and approved by the commission;

(B) has a commission-approved organization report as required by Section 91.142;

(C) has a commission-approved bond, letter of credit, or cash deposit under Sections 91.103-91.107 covering the well; and

(D) places the well in compliance with commission rules.

(3) "Nonoperator" means a person who owns a working interest in a well at the time the well is required to be plugged pursuant to commission rules and is not an operator as defined in Subdivision (2) of this subsection.

(4) "Commission" means the Railroad Commission of Texas.

(5) "Well-site equipment" means any production-related equipment or materials specific to the well being plugged, including motors, pumps, pump jacks, tanks, tank batteries, separators, compressors, casing, tubing, and rods.

(6) "Lease" means the lease on which a well made the subject of a plugging contract is located.

(7) "Delinquent inactive well" means an inactive well for which, after notice and opportunity for a hearing, the commission has not extended the plugging deadline.

(8) "Plugging" includes replugging.

(9) "Cost calculation for plugging an inactive well" means the commission's calculated cost for each foot of well depth plugged based on average actual plugging costs for wells reported by the commission for the preceding state fiscal year for the commission oil and gas division district in which the inactive well is located.

(10) "Enhanced oil recovery project":

(A) means:

(i) a commission-approved project that uses any process for the displacement of oil or other hydrocarbons from a reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process;

(ii) a certified project described by Section 202.054, Tax Code; or

(iii) any other project approved by the commission for enhanced oil recovery; and

(B) does not include a water disposal project.

(11) "Good faith claim" means a factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(12) "Inactive well" means an unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.

(13) "Physically terminated electric service to the well's production site" means that electric service to an inactive well site has been disconnected at a point on the electric service lines most distant from the production site toward the main supply line in a manner that will not interfere with electrical supply to adjacent operations, including cathodic protection units.

(b) The terms operator and nonoperator as defined in this section do not mean a royalty interest owner or an overriding royalty interest owner.

Acts 1977, 65th Leg., p. 2552, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5255, ch. 967, Sec. 4, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5406, ch. 1002, Sec. 1, eff. Aug. 29, 1983; Acts 1993, 73rd Leg., ch. 882, Sec. 1, eff. Sept. 1, 1993; Acts 1993, 73rd Leg., ch. 515,

Sec. 1, eff. Jan. 1, 1994; Acts 1997, 75th Leg., ch. 89, Sec. 1, eff. Sept. 1, 1997; Acts 2001, 77th Leg., ch. 1233, Sec. 11, eff. Sept. 1, 2004. Amended by: Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 1, eff. September 1, 2009.

Sec. 89.003. APPLICABILITY. The provisions of this chapter do not alter causes of action arising before August 30, 1965.

Acts 1977, 65th Leg., p. 2553, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER B. DUTY TO PLUG WELLS

Sec. 89.011. DUTY OF OPERATOR. (a) The operator of a well shall properly plug the well when required and in accordance with the commission's rules that are in effect at the time of the plugging.

(b) If useable quality water zones are present, the operator shall verify the placement of the plug at the base of the deepest fresh water zone required to be protected. The well is considered to have been properly plugged only when the verification is satisfactory and meets commission requirements.

(c) If, for the use of the surface owner, the operator of the well plugs the well back to produced fresh water, the duty of the operator to properly plug the well ends only when:

(1) the well has been properly plugged in accordance with commission requirements; and

(2) the surface owner has obtained a permit for the well from the groundwater conservation district, if applicable.

(d) Subsections (b) and (c) apply only to wells plugged on or after the effective date of this Act.

(e) The duty of a person to plug an unplugged well that has ceased operation ends only if the person's interest in the well is sold or conveyed while the well is in compliance with rules of the commission relating to safety or the prevention or

control of pollution and the provisions of Sections 89.002(a)(2)(A)-(D) have been met. The person acquiring the seller's interest through such a sale or conveyance succeeds the seller as the operator of the well for the purpose of plugging responsibility once the provisions of Sections 89.002(a)(2)(A)-(D) have been met.

Acts 1977, 65th Leg., p. 2553, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1993, 73rd Leg., ch. 882, Sec. 2, eff. Sept. 1, 1993; Acts 1997, 75th Leg., ch. 89, Sec. 2, eff. Sept. 1, 1997; Acts 2001, 77th Leg., ch. 1233, Sec. 12, eff. Sept. 1, 2001.

Sec. 89.012. DUTY OF NONOPERATOR. If the operator of a well fails to comply with Section 89.011 of this code, each nonoperator is responsible for his proportionate share of the cost of the proper plugging of the well within a reasonable time, according to the rules of the commission in effect at the time the responsibility attaches.

Acts 1977, 65th Leg., p. 2553, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

SUBCHAPTER B-1. PLUGGING OF CERTAIN INACTIVE WELLS

Sec. 89.021. APPLICABILITY. This subchapter does not apply to a bay or offshore well as defined by commission rules.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009.

Sec. 89.022. PLUGGING OF INACTIVE WELLS REQUIRED. (a) Except as provided by Section 89.023, on or before the date the operator is required to renew the operator's organization report required by Section 91.142, an operator of an inactive well must

plug the well in accordance with statutes and commission rules in effect at the time of plugging.

(b) Notwithstanding Subsection (a), a person who assumes responsibility for the physical operation and control of an existing inactive well must satisfy the requirements of Sections 89.023(a)(1) and (3) not later than six months after the date the commission approves the initial form described by Section 89.002(a)(2) and filed with the commission under which the person assumes responsibility for the well.

(c) The commission may not renew or approve the organization report required by Section 91.142 for an operator that fails to comply with the requirements of this subchapter.

(d) Before the commission issues an order refusing to renew an operator's organization report under Subsection (c), an authorized commission employee or a person designated by the commission for that purpose must determine whether the operator has failed to comply with the requirements of this subchapter. If the authorized commission employee or designated person determines that the organization report does not qualify for renewal on that ground, the authorized commission employee or designated person must:

(1) notify the operator of the determination;

(2) provide the operator with a written statement of the reasons the organization report does not qualify for renewal; and

(3) notify the operator that the operator has 90 days to comply with the requirements of this subchapter.

(e) After the expiration of the period specified by Subsection (d)(3), the authorized commission employee or designated person shall determine whether the organization report qualifies for renewal and notify the operator of the determination. If the authorized commission employee or designated person determines that the organization report does not qualify for renewal because the operator has continued to fail to comply with the requirements of this subchapter, the operator, not later than the 30th day after the date of the

determination, may request a hearing regarding the determination. The operator shall pay the costs associated with a hearing requested under this subsection.

(f) If the commission determines following the hearing that the operator has failed to comply with the requirements of this subchapter or the operator fails to file a timely request for a hearing, the commission by order shall refuse to renew the organization report. The organization report remains in effect until the commission's order becomes final.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 1, eff. June 17, 2011.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 1150, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.023. EXTENSION OF DEADLINE FOR PLUGGING INACTIVE WELL.

(a) The commission may grant an extension of the deadline for plugging an inactive well if the operator maintains a current organization report with the commission as required by Section 91.142 and if, on or before the date of renewal of the operator's organization report as required by that section, the operator files with the commission an application for an extension that includes:

(1) an affirmation that complies with Section 89.029;

(2) a statement that the operator has, and on request will provide, evidence of a good faith claim to a continuing right to operate the well; and

(3) at least one of the following:

(A) documentation that since the preceding date that the operator's organization report was required to be renewed the operator has plugged, or restored to active

operation as defined by commission rule, a number of inactive wells equal to or greater than 10 percent of the number of inactive wells operated by the operator on that date;

(B) an abeyance of plugging report on a form approved by the commission that:

(i) is in the form of a certification signed by a person licensed by the Texas Board of Professional Engineers and Land Surveyors as an engineer or by the Texas Board of Professional Geoscientists;

(ii) includes:

(a) an affirmation by the licensed person that the well has:

(1) a reasonable expectation of economic value in excess of the cost of plugging the well for the duration of the period covered by the report, based on the cost calculation for plugging an inactive well; and

(2) a reasonable expectation of being restored to a beneficial use that will prevent waste of oil or gas resources that otherwise would not be produced if the well were plugged; and

(b) appropriate documentation demonstrating the basis for the affirmation of the well's future utility; and

(iii) specifies the field and the covered wells within that field in a format prescribed by the commission;

(C) a statement that the well is part of an enhanced oil recovery project;

(D) if the operator of the well is not currently otherwise required by commission rule or order to conduct a fluid level or hydraulic pressure test of the well, documentation of the results of a successful fluid level or hydraulic pressure test of the well conducted in accordance with the commission's rules in effect at the time the test is conducted;

(E) a supplemental bond, letter of credit, or cash deposit sufficient for each well specified in the application that:

(i) complies with the requirements of Chapter 91; and

(ii) is of an amount at least equal to the cost calculation for plugging an inactive well for each well specified in the application;

(F) documentation of the deposit with the commission each time the operator files an application of an amount of escrow funds as prescribed by commission rule that equal at least 10 percent of the total cost calculation for plugging an inactive well for each well specified in the application; or

(G) if the operator is a publicly traded entity:

(i) the following documents:

(a) a copy of the operator's federal documents filed to comply with Financial Accounting Standards Board Statement No. 143, Accounting for Asset Retirement Obligations; and

(b) an original, executed Uniform Commercial Code Form 1 Financing Statement, filed with the secretary of state, that:

(1) names the operator as the "debtor" and the Railroad Commission of Texas as the "secured creditor"; and

(2) specifies the funds covered by the documents described by Sub-subparagraph (a) in the amount of the cost calculation for plugging an inactive well for each well specified in the application; or

(ii) a blanket bond in the amount of the lesser of:

(a) the cost calculation for plugging any inactive wells; or

(b) $2 million.

(b) Notwithstanding Subsection (a), an operator may not obtain an extension of the deadline for plugging an inactive well by complying with that subsection if the plugging of the well is otherwise required by commission rules or orders.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 2, eff. June 17, 2011; Acts 2019, 86th Leg., R.S., Ch. 1232 (H.B. 1523), Sec. 2.11, eff. September 1, 2019.

Sec. 89.024. ABEYANCE OF PLUGGING REPORT. (a) An abeyance of plugging report filed under Section 89.023(a)(3)(B) is valid for a period of not more than five years.

(b) An abeyance of plugging report may cover more than one well in a field but may not cover more than one field.

(c) An abeyance of plugging report may not be transferred to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new abeyance of plugging report or otherwise comply with the requirements of this subchapter on or before the deadline provided by Section 89.022(b). This subsection does not prohibit the transfer of an abeyance of plugging report in the event of a change of name of an operator.

(d) An operator who files an abeyance of plugging report must pay an annual fee of $100 for each well covered by the report. A fee collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 3, eff. June 17, 2011; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.07, eff. September 28, 2011.

Sec. 89.025. ENHANCED OIL RECOVERY PROJECT. (a) For purposes of Section 89.023(a)(3)(C), an inactive well is considered to be part of an enhanced oil recovery project if the well is located on a unit or lease or in a field associated with such a project.

(b) A statement that an inactive well is part of an enhanced oil recovery project may not be transferred to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new statement that the well is part of such a project or otherwise comply with the requirements of this subchapter on or before the deadline provided by Section 89.022(b). This subsection does not prohibit the transfer of a statement that a well is part of an enhanced oil recovery project in the event of a change of name of an operator.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 4, eff. June 17, 2011.

Sec. 89.026. FLUID LEVEL OR HYDRAULIC PRESSURE TEST. (a) Documentation filed under Section 89.023(a)(3)(D) of the results of a successful fluid level test is valid for a period of one year from the date of the test. Documentation filed under that section of the results of a successful hydraulic pressure test is valid for a period of not more than five years from the date of the test.

(b) The operator must notify the office of the commission oil and gas division district in which an inactive well is located at least three days before the date the operator conducts a fluid level or hydraulic pressure test of the well and may not conduct the test without the approval of the office. The commission may require that a test be witnessed by a commission employee.

(c) Documentation of the results of a successful fluid level or hydraulic pressure test may be transferred to a new operator of an existing inactive well.

(d) An operator who files documentation described by Subsection (a) must pay an annual fee of $50 for each well covered by the documentation. A fee collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009.Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 5, eff. June 17, 2011; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.08, eff. September 28, 2011.

Sec. 89.027. SUPPLEMENTAL FINANCIAL ASSURANCE. (a) A supplemental bond, letter of credit, or cash deposit filed under Section 89.023(a)(3)(E) is in addition to any other financial assurance otherwise required of the operator or for the well.

(b) A supplemental bond, letter of credit, or cash deposit may not be transferred to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new supplemental bond, letter of credit, or cash deposit or otherwise comply with the requirements of this subchapter by the deadline provided by Section 89.022(b).

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 6, eff. June 17, 2011.

Sec. 89.028. ESCROW FUNDS. (a) Escrow funds described by Section 89.023(a)(3)(F) must be deposited with the commission each time an operator files an application for an extension of the deadline for plugging an inactive well.

(b) Escrow funds deposited with the commission may be released only with the approval of the commission as prescribed by commission rule.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 562 (H.B. 3134), Sec. 7, eff. June 17, 2011.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 2663, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.029. AFFIRMATION REGARDING SURFACE REQUIREMENTS. (a) An application for an extension of the deadline for plugging an inactive well must include a written affirmation by the operator:

(1) that the operator has physically terminated electric service to the well's production site; and

(2) stating the following, as applicable, if the operator does not own the surface of the land on which the well is located:

(A) if the well has been inactive for at least five years but for less than 10 years as of the date of renewal of the operator's organization report, that the operator has emptied or purged of production fluids all piping, tanks, vessels, and equipment associated with and exclusive to the well; or

(B) if the well has been inactive for at least 10 years as of the date of renewal of the operator's organization report, that the operator has removed all surface process equipment and related piping, tanks, tank batteries, pump jacks, headers, and fences, as well as junk and trash as defined by commission rule, associated with and exclusive to the well.

(b) An operator of an inactive well shall leave a clearly visible marker at the wellhead of the well.

(c) The commission shall adopt rules regulating the transfer of material described by Subsection (a)(2)(B) and restricting its accumulation on an active lease.

(d) Notwithstanding Subsection (a), an operator may be eligible for a temporary extension of the deadline for plugging an inactive well or a temporary exemption from the requirements of Subsection (a) as provided by commission rule if the operator is unable to comply with the requirements of that subsection because of safety concerns or required maintenance of the well site and the operator includes with the application a written affirmation of the facts regarding the safety concerns or maintenance.

(e) An operator may be eligible for an extension of the deadline for plugging a well without complying with Subsection (a)(2)(B) if the well is located on a unit or lease or in a field associated with an enhanced oil recovery project and the operator includes a statement in the written affirmation that the well is part of such a project. The exemption provided by this subsection applies only to the equipment required for the project.

(f) Notwithstanding the other provisions of this subchapter, the commission shall adopt rules providing for the phase-in of the duty to comply with Subsection (a)(2)(B) over a period of five years beginning September 1, 2010. The rules must require the operators of one-fifth of the wells that are subject to that subsection in each year during the phase-in period to comply with that subsection.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009.

Sec. 89.030. REVOCATION OF EXTENSION OF DEADLINE FOR PLUGGING INACTIVE WELL. The commission may revoke an extension of the deadline for plugging an inactive well granted under this

subchapter if the commission determines, after notice and an opportunity for a hearing, that the applicant is ineligible for the extension under the commission's rules or orders.

Added by Acts 2009, 81st Leg., R.S., Ch. 442 (H.B. 2259), Sec. 2, eff. September 1, 2009.

SUBCHAPTER C. POWERS AND DUTIES OF THE COMMISSION

Sec. 89.041. DETERMINING PROPER PLUGGING. If it comes to the attention of the commission that a well that has been abandoned or is not being operated is causing or is likely to cause pollution of fresh water above or below the ground or if gas or oil is escaping from the well, the commission may determine at a hearing, after due notice, whether or not the well was properly plugged as provided in Section 89.011 or Section 89.012 of this code.

Acts 1977, 65th Leg., p. 2553, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983.

Sec. 89.042. COMMISSION ORDER TO PLUG. (a) If the commission finds that the well was not properly plugged, it shall order the operator to plug the well according to the rules of the commission in effect at the time the order is issued.

(b) If the operator cannot be found or is no longer in existence or has no assets with which to properly plug the well, the commission shall order the nonoperators to plug the well according to the rules of the commission in effect at the time the order is issued.

(c) Repealed by Acts 1983, 68th Leg., p. 5409, ch. 1002, Sec. 3, eff. Aug. 29, 1983.

Acts 1977, 65th Leg., p. 2553, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5409, ch. 1002, Sec. 3, eff. Aug. 29, 1983.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 3619, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.043. PLUGGING BY COMMISSION. (a) If the commission determines at a hearing under Section 89.041 of this code that a well has not been properly plugged or needs replugging, the commission, through its employees or through a person acting as agent for the commission, may plug or replug the well if:

(1) the well was properly plugged according to rules in effect at the time the well was abandoned or ceased to be operated; or

(2) neither the operator nor nonoperator properly plugged the well, and

(A) neither the operator nor nonoperator can be found; or

(B) neither the operator nor nonoperator has assets with which to properly plug the well.

(b) If a well is leaking salt water, oil, or gas or is likely to leak salt water, oil, or gas, and the leakage will cause or is likely to cause a serious threat of pollution or injury to the public health, the commission, through its employees or agents, may direct the operator to take remedial action or to plug the well or may plug or replug the well without holding a hearing under Section 89.041 of this code or giving notice under Subsection (c) of this section.

(c) Not later than the 30th day before the date the commission enters into a contract to plug a delinquent inactive well, the commission shall send a notice by certified mail to

the operator of the well at the address last reported to the commission as required by Section 91.142 and commission rules. The notice shall direct the operator to plug the well and shall state that:

(1) the commission may plug the well and foreclose its statutory lien under Section 89.083 unless the operator requests a hearing not later than the 10th day after the date the operator receives the notice;

(2) if the commission forecloses its statutory lien under Section 89.083, all well-site equipment will be presumed to have been abandoned and the commission may dispose of the equipment and hydrocarbons from the well as provided by Section 89.085;

(3) if the commission plugs the well, the commission:

(A) by order may require the operator to reimburse the commission for the plugging costs; or

(B) may request the attorney general to file suit against the operator to recover those costs;

(4) the commission has a statutory lien on all well-site equipment under Section 89.083; and

(5) the lien described by Subdivision (4) is foreclosed by operation of law if the commission does not receive a valid and timely request for a hearing before the 15th day after the date the notice is mailed.

(d) The operator of a well made the subject of a prior commission final order directing that it be plugged is not entitled to a second hearing under this section.

(e) The commission shall file for record a copy of the notice in the office of the county clerk of the county in which the well is located. The notice filed with the county need not be acknowledged. The copy of the notice filed in the office of the county clerk must contain the section, block, survey, and abstract number, when available to the commission, of the land on which the well is located. The clerk shall record the notice in the real property records of the county. The commission shall not be charged a fee for the filing or recording of the

notice. The commission shall furnish a copy of the notice to a holder of a lien on the well or a nonoperator on that person's request. For purposes of title insurance policies issued under authority of Title 11, Insurance Code, this notice is not a notice of enforcement or violation of law, ordinance, or governmental regulation unless the notice contains a legally sufficient description of the specific land on which the well is located.

(f) At the request of the commission, the attorney general may file suit to enforce an order issued by the commission under Subsection (c)(3)(A).

Acts 1977, 65th Leg., p. 2554, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983; Acts 1993, 73rd Leg., ch. 515, Sec. 2, eff. Jan. 1, 1994; Acts 1995, 74th Leg., ch. 928, Sec. 1, eff. Aug. 28, 1995; Acts 1999, 76th Leg., ch. 29, Sec. 1, eff. Aug. 30, 1999; Acts 1999, 76th Leg., ch. 57, Sec. 1, eff. May 10, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 13, eff. Sept. 1, 2001. Amended by: Acts 2005, 79th Leg., Ch. 728 (H.B. 2018), Sec. 11.147, eff. September 1, 2005.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 3619, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.044. RIGHT TO ENTER ON LAND. (a) The commission or its employees or agents, the operator, or the nonoperator, on proper identification, may enter the land of another for the purpose of plugging or replugging a well that has not been properly plugged.

(b) A prospective operator who has been authorized under Section 89.047 to conduct a surface inspection of a well, on

proper identification, may enter the land of another for the sole purpose of conducting the inspection.

Acts 1977, 65th Leg., p. 2554, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983. Amended by: Acts 2005, 79th Leg., Ch. 267 (H.B. 2161), Sec. 3, eff. January 1, 2006.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 3619 and S.B. 1146, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.045. LIABILITY FOR DAMAGES. The commission and its employees and agents, the operator, and the nonoperator are not liable for any damages that may occur as a result of acts done or omitted to be done by them or each of them in a good-faith effort to carry out this chapter.

Acts 1977, 65th Leg., p. 2554, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983.

Sec. 89.046. PENALTIES AND OTHER RELIEF. The plugging or replugging of a well by the commission does not prevent the commission from seeking penalties or other relief provided by law from any person who is required by law, rules adopted by the commission, or a valid order of the commission to plug the well.

Added by Acts 1983, 68th Leg., p. 5256, ch. 967, Sec. 5, eff. Sept. 1, 1983.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 1762, 89th

Legislature, Regular Session, for amendments affecting the following section.

Sec. 89.047. ORPHANED WELL REDUCTION PROGRAM. (a) In this section:

(1) "Depth of the well" means the vertical depth of a well as measured in linear feet from the surface to the lowest perforation of the casing of the well that is within the commission-designated correlative interval for the field for which the well is issued a permit.

(1-a) "Energy conservation well" means a well used for the retention of energy that may be used to provide dispatchable generation of electricity for the power grid.

(1-b) "Geothermal energy and associated resources" has the meaning assigned by Section 141.003.

(2) "Operator in good standing" means an operator who:

(A) has a commission-approved organization report;

(B) is the designated operator of at least one well within the jurisdiction of the commission;

(C) has filed with the commission under Section 91.104 a bond, letter of credit, or cash deposit in an amount sufficient to qualify to operate one or more additional wells; and

(D) is not the subject of a commission or court order regarding a violation of a commission rule with which the operator has not complied or a complaint that has been docketed by the commission alleging a violation of a commission rule.

(3) "Orphaned well" means a well:

(A) for which the commission has issued a permit;

(B) for which production of oil or gas or another activity under the jurisdiction of the commission has not been reported to the commission for the preceding 12 months; and

(C) whose operator's commission-approved organization report has lapsed.

(4) "Producing well" means a well classified by the commission as an oil or gas well in accordance with commission rules.

(5) "Service well" means a well for which the commission has issued a permit that is not a producing well. The term includes an injection, disposal, or brine mining well.

(b) A person who is considering assumption of operatorship and regulatory responsibility for an orphaned well may nominate the well under consideration by filing a request on a form prescribed by the commission notifying the commission that the person seeks authority to conduct a surface inspection of the well to determine whether the person desires to be designated by the commission as the operator of the well.

(c) If the person is an operator in good standing and the well is not already subject to a nomination, the commission shall accept the nomination and issue a written confirmation to the person of the person's authority to conduct a surface inspection of the nominated well for a stated period not to exceed 30 days.

(d) A person to whom a confirmation is issued under Subsection (c) may conduct a surface inspection of the well. The person must deliver written notice to the owner of record of the surface estate and any occupant of the tract on which the well is located at least three days before the date of the inspection. The notice must:

(1) identify the orphaned well;

(2) state the name, address, and telephone number of the person;

(3) state the date the person intends to conduct the surface inspection;

(4) state the name of at least one representative of the person who will participate in the surface inspection; and

(5) state that the person intends to inspect the orphaned well in accordance with this section for the purpose of assessing the current status and viability of the well.

(e) In conducting a surface inspection of the orphaned well, the person may visually inspect the well and all related equipment, tanks, and other facilities and may conduct noninvasive testing such as using a gauge to determine the pressure present at the wellhead but may not produce oil or gas from the well, reenter the well, pull tubing from or perform any other type of downhole work on the well, conduct a salvage operation on the well, or remove any tangible item from the well site.

(f) The commission shall designate the person as the operator of the well if the person files with the commission:

(1) a factually supported claim based on a recognized legal theory to a continuing possessory right in:

(A) the mineral estate accessed by the well, as established by a current oil and gas lease, a recorded deed conveying a fee interest in the mineral estate, or any other documentation of an interest in the mineral estate;

(B) the geothermal energy and associated resources estate accessed by the well, as established by a current geothermal lease, a recorded deed conveying a fee interest in the geothermal estate, or any other documentation of an interest in the geothermal estate; or

(C) the geologic space accessed by the well for the purpose of an energy conservation well, as established by a recorded deed conveying a fee interest in the space accessed by the well or any other documentation of an interest in that space;

(2) a completed certificate of compliance; and

(3) a nonrefundable fee in the amount of $250.

(g) A fee collected under Subsection (f) shall be deposited to the credit of the general revenue fund and may be appropriated only to the commission to be used to enforce the

laws and rules concerning oil and gas conservation and waste and pollution prevention.

(h) A person who is designated as the operator of an orphaned well on or after January 1, 2006, and not later than December 31, 2007, is entitled to receive:

(1) a nontransferable exemption from severance taxes for all future production from the well as provided by Section 202.060, Tax Code;

(2) a nontransferable exemption from the fees provided by Sections 81.116 and 81.117 for all future production from the well; and

(3) a payment from the commission in an amount equal to the depth of the well multiplied by 50 cents for each foot of well depth if, not later than the third anniversary of the date the commission designates the person as the operator of the well, the person brings the well back into continuous active operation or plugs the well in accordance with commission rules.

(i) A well is considered to be in continuous active operation for purposes of Subsection (h)(3) if:

(1) the well is a producing well and the well has produced at least 10 barrels of oil or 100 mcf of gas per month for at least three consecutive months as shown in the records of the commission and as authorized by a permit issued by the commission; or

(2) the well is a service well and the well has been used for the disposal or injection of oil and gas wastes or another purpose related to the production of oil or gas for at least three consecutive months as shown in the records of the commission and as authorized by a permit issued by the commission.

(j) The commission shall make payments to operators under Subsection (h)(3) annually in the same order the commission determines the operators to be entitled to the payments. The aggregate amount of payments in a state fiscal year under that subsection may not exceed $500,000. An operator may not receive:

(1) more than one payment under that subsection for the same well; or

(2) cumulative payments in an amount that exceeds the amount of the bond, letter of credit, or cash deposit the operator has filed with the commission under Section 91.104.

Added by Acts 2005, 79th Leg., Ch. 267 (H.B. 2161), Sec. 4, eff. January 1, 2006. Amended by: Acts 2023, 88th Leg., R.S., Ch. 87 (S.B. 1210), Sec. 1, eff. September 1, 2023; Acts 2023, 88th Leg., R.S., Ch. 87 (S.B. 1210), Sec. 2, eff. September 1, 2023.

Sec. 89.048. PLUGGING OF WELL BY SURFACE ESTATE OWNER. (a) In this section, "orphaned well" has the meaning assigned by Section 89.047.

(b) The owner of an interest in the surface estate of a tract of land on which an orphaned well is located may contract with a commission-approved well plugger to plug the well.

(c) If the surface estate owner enters into a contract under Subsection (b), the well plugger shall:

(1) not later than the 30th day before the date the well is plugged, mail notice of its intent to plug the well to the operator of the well at the operator's address as shown by the records of the commission;

(2) assume responsibility for the physical operation and control of the well as shown by a form the person files with the commission and the commission approves;

(3) file a bond, letter of credit, or cash deposit covering the well as required by Section 91.107; and

(4) plug the well in accordance with commission rules.

(d) On successful plugging of the well by the well plugger, the surface estate owner may submit documentation to the commission of the cost of the well-plugging operation. The commission shall reimburse the surface estate owner from money in the oil and gas regulation and cleanup fund in an amount not to exceed 50 percent of the lesser of:

(1) the documented well-plugging costs; or

(2) the average cost incurred by the commission in the preceding 24 months in plugging similar wells located in the same general area.

(e) The commission shall adopt any rules reasonably necessary to implement this section.

Added by Acts 2005, 79th Leg., Ch. 267 (H.B. 2161), Sec. 4, eff. January 1, 2006. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.09, eff. September 28, 2011.

SUBCHAPTER D. COSTS OF PLUGGING WELLS

Sec. 89.081. CAUSE OF ACTION FOR DISPROPORTIONATE SHARE OF COST. If an operator or nonoperator owns only a partial interest in the well or oil and gas and the operator or nonoperator pays a larger proportion of the cost of plugging the well than his proportionate interest in the well or oil and gas, he has a cause of action against the other operators and nonoperators for their proportionate shares of the cost of plugging.

Acts 1977, 65th Leg., p. 2554, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983.

Sec. 89.083. FIRST LIEN ON EQUIPMENT; CAUSE OF ACTION IF COMMISSION PLUGS. (a) If a well has not been plugged by the deadline for plugging established by commission rules, the state has a first lien, superior to all other preexisting and subsequent liens and security interests, on the operator's and nonoperator's interests in well-site equipment, in the amount of the total costs of removing well-site equipment from the well, plugging the well, and transporting, storing, and disposing of the well-site equipment.

(b) The lien arises on the date by which the well is required to be plugged under commission rules.

(c) The lien may be foreclosed by judicial action or commission order at any time after notice and an opportunity for a hearing. If notice is mailed under Section 89.043 and if the lien is not previously foreclosed, the lien is foreclosed by operation of law on the 15th day after the date the notice is mailed unless the commission has received a valid and timely request for a hearing before that date. The commission is not required to give notice or an opportunity for a hearing to subordinate lienholders or nonoperators before foreclosing the lien.

(d) The lien is extinguished if the well is plugged or otherwise brought into compliance in accordance with commission rules by any person authorized to do so before the commission enters into a plugging contract.

(e) The lien is extinguished as to any item of well-site equipment that is lawfully removed by any person other than the operator or a nonoperator pursuant to a lien, lease, judgment, written contract, or security agreement before the commission sends notice under Section 89.043(c). A person may not remove from an inactive well site any equipment necessary to prevent the well from serving as a conduit for the passage of oil, gas, saltwater, oil and gas wastes, or freshwater from one stratum or formation to another or to the surface or from the surface downward except in the course of plugging in accordance with commission rules.

(f) If the commission plugs a well under Sections 89.043 through 89.044 of this code, the state has a cause of action for all reasonable expenses incurred in plugging or replugging the well and not recovered under Section 89.085 of this code or through reimbursement to the commission.

(g) The cause of action is:

(1) first, against the operator, to be secured by a first lien, superior to all preexisting and subsequent liens and security interests, on the operator's interest in the oil and

gas in the land and the fixtures, machinery, and equipment found or used on the land where the well is located; and

(2) second, against a nonoperator at the time the well should have been plugged, to be secured by a lien on the nonoperator's interest in the oil and gas in the land. A nonoperator may be made a party defendant in the suit against the operator.

(h) The commission:

(1) by order may require the operator and any nonoperator to reimburse the commission for all reasonable expenses incurred in plugging a well; or

(2) may request the attorney general to file suit against the operator and any nonoperator to recover those expenses.

(i) At the request of the commission, the attorney general may file suit to enforce an order issued by the commission under Subsection (h)(1).

(j) Money collected in a suit under this section shall be deposited in the oil and gas regulation and cleanup fund.

(k) A civil action for reimbursement under this section may be brought in Travis County, the county in which the plugged well is located, or the county in which any defendant resides.

Acts 1977, 65th Leg., p. 2555, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983; Acts 1983, 68th Leg., p. 5407, ch. 1002, Sec. 2, eff. Aug. 29, 1983; Acts 1991, 72nd Leg., ch. 603, Sec. 6, eff. Sept. 1, 1991; Acts 1993, 73rd Leg., ch. 515, Sec. 3, eff. Jan. 1, 1994; Acts 1999, 76th Leg., ch. 29, Sec. 2, eff. Aug. 30, 1999; Acts 1999, 76th Leg., ch. 57, Sec. 2, eff. May 10, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 14, eff. Sept. 1, 2001. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.10, eff. September 28, 2011.

Sec. 89.084. MONEY PAID COMMISSION BY PRIVATE PERSON. (a) The commission may accept money from private persons and use the money to plug or replug a well.

(b) Paying money to the commission is not an admission that the person paying the money is obligated to plug or replug the well. Evidence that a person has paid money to the commission is not admissible against the person in a suit in which the person's obligation to plug a well is an issue and introducing the evidence is a compulsory ground for mistrial.

Acts 1977, 65th Leg., p. 2555, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 89.085. POSSESSION AND SALE OF EQUIPMENT TO COVER PLUGGING COSTS. (a) When the commission forecloses its lien under Section 89.083 on a delinquent inactive well, well-site equipment and any amount of hydrocarbons from the well that is stored on the lease are presumed to have been abandoned and may be disposed of by the commission in a commercially reasonable manner by either or both of the following methods:

(1) entering into a plugging contract that provides that the person plugging or cleaning up pollution, or both, will take title to well-site equipment, hydrocarbons from the well that are stored on the lease, or hydrocarbons recovered during the plugging operation in exchange for a sum of money deducted as a credit from the contract price; or

(2) selling the well-site equipment, hydrocarbons from the well that are stored on the lease, or hydrocarbons recovered during the plugging operation at a public auction or a public or private sale.

(b) The commission shall assign separate costs to:

(1) removing well-site equipment;

(2) plugging the well; and

(3) transporting, storing, and disposing of the well-site equipment.

(c) The commission shall dispose of well-site equipment or hydrocarbons under this section at a price or value that reflects the generally recognized market value of the equipment or hydrocarbons, with allowances for physical condition.

(d) The commission shall deposit money received from the sale of well-site equipment or hydrocarbons under this section to the credit of the oil and gas regulation and cleanup fund. The commission shall separately account for money and credit received for each well.

(e) A person who acquires well-site equipment or hydrocarbons under this section by sale or contract receives a clear title, free of all prior legal or equitable claims of whatever nature, whether perfected or inchoate.

(f) Not later than the 30th day after the date well-site equipment or hydrocarbons are disposed of under this section, the commission shall mail a notice by first class mail to the operator of the well at the address last reported to the commission as required by Section 91.142 of this code and commission rules and, on request, to any lienholder or nonoperator.

(g) The notice required by Subsection (f) of this section must include:

(1) the lease name;

(2) the well number;

(3) the county in which the well is located;

(4) the abstract number of the property on which the lease is situated;

(5) the commission lease or gas well identification number or drilling permit number;

(6) a list of the property disposed of under this section; and

(7) a statement that any person who has a legal or equitable ownership or security interest in the equipment or hydrocarbons that was in existence on the date the commission foreclosed its statutory lien may file a claim with the commission.

(h) Not later than the 180th day after the date the well-site equipment or hydrocarbons are disposed of under this section, the commission shall publish a notice that states:

(1) the lease name;

(2) the well number;

(3) the county in which the well is located;

(4) the commission lease or gas well identification number or drilling permit number; and

(5) that equipment or hydrocarbons if applicable from the well and lease were disposed of under this section and that any person who has a legal or equitable ownership or security interest in the equipment or hydrocarbons that was in existence on the date the commission foreclosed its statutory lien may file a claim with the commission.

(i) The commission shall publish the notice required under Subsection (h) of this section in a newspaper of general circulation in the county in which the lease is located. A single notice may contain the information required for more than one well and lease. A notice given under this section following the plugging of a well may be combined with a notice given under Section 91.115 of this code following the cleanup of a site or facility.

Added by Acts 1985, 69th Leg., ch. 715, Sec. 1, eff. Aug. 26, 1985. Amended by Acts 1989, 71st Leg., ch. 755, Sec. 1, eff. Sept. 1, 1989; Acts 1993, 73rd Leg., ch. 515, Sec. 4, eff. Jan. 1, 1994; Acts 2001, 77th Leg., ch. 1233, Sec. 15, eff. Sept. 1, 2001. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.11, eff. September 28, 2011.

Sec. 89.086. CLAIMS AGAINST OIL AND GAS REGULATION AND CLEANUP FUND. (a) A person with a legal or equitable ownership or security interest in well-site equipment or hydrocarbons disposed of under Section 89.085 may make a claim against the oil and gas regulation and cleanup fund unless an element of the

transaction giving rise to the interest occurs after the commission forecloses its statutory lien under Section 89.083.

(b) The commission shall adopt a form on which a person may file a sworn claim with the commission.

(c) A claimant must identify the well-site equipment or hydrocarbons in which the claimant has an interest and state the amount of the property interest as of the date the commission foreclosed its statutory lien under Section 89.083.

(d) The commission may require a person to include with a claim documentation that substantiates the claim or to disclose whether the claimant was an operator or nonoperator of the well.

(e) The commission may set a hearing to receive evidence on a claim filed under this section. The commission shall notify the claimant of the date, time, and place of a hearing.

(f) If the commission holds a hearing, the commission shall issue:

(1) a decision on the claim;

(2) a statement of findings of fact that includes the substance of the evidence heard; and

(3) the conclusions of law that support the decision.

(g) The commission shall consider the validity of claims in the order in which the claims are filed.

(h) The commission shall suspend an amount of money in the oil and gas regulation and cleanup fund equal to the amount of the claim until the claim is finally resolved. If the provisions of Subsection (k) prevent suspension of the full amount of the claim, the commission shall treat the claim as two consecutively filed claims, one in the amount of funds available for suspension and the other in the remaining amount of the claim.

(i) A claim made by or on behalf of the operator or a nonoperator of a well or a successor to the rights of the operator or nonoperator is subject to a ratable deduction from the proceeds or credit received for the well-site equipment to cover the costs incurred by the commission in removing the equipment or hydrocarbons from the well or in transporting,

storing, or disposing of the equipment or hydrocarbons. A claim made by a person who is not an operator or nonoperator is subject to a ratable deduction for the costs incurred by the commission in removing the equipment from the well. If a claimant is a person who is responsible under law or commission rules for plugging the well or cleaning up pollution originating on the lease or if the claimant owes a penalty assessed by the commission or a court for a violation of a commission rule or order, the commission may recoup from or offset against a valid claim an expense incurred by the oil and gas regulation and cleanup fund that is not otherwise reimbursed or any penalties owed. An amount recouped from, deducted from, or offset against a claim under this subsection shall be treated as an invalid portion of the claim and shall remain suspended in the oil and gas regulation and cleanup fund in the manner provided by Subsection (j).

(j) If the commission finds that a claim is valid in whole or in part, the commission shall pay the valid portion of the claim from the suspended amount in the oil and gas regulation and cleanup fund not later than the 30th day after the date of the commission's decision. If the commission finds that a claim is invalid in whole or in part, the commission shall continue to suspend in the oil and gas regulation and cleanup fund an amount equal to the invalid portion of the claim until the period during which the commission's decision may be appealed has expired or, if appealed, during the period the case is under judicial review. If on appeal the district court finds the claim valid in whole or in part, the commission shall pay the valid portion of the claim from the suspended amount in the oil and gas regulation and cleanup fund not later than 30 days after the date the court's judgment becomes unappealable. On the date the commission's decision is not subject to judicial review, the commission shall release from the suspended amount in the oil and gas regulation and cleanup fund the amount of the claim held to be invalid.

(k) If the aggregate of claims paid and money suspended that relates to well-site equipment or hydrocarbons from a particular well equals the total of the actual proceeds and credit realized from the disposition of that equipment or those hydrocarbons, the oil and gas regulation and cleanup fund is not liable for any subsequently filed claims that relate to the same equipment or hydrocarbons unless and until the commission releases from the suspended amount money derived from the disposition of that equipment or those hydrocarbons. If the commission releases money, then the commission shall suspend money in the amount of subsequently filed claims in the order of filing.

(l) A person who informs a potential claimant that the potential claimant may be entitled to file a claim under this section or who files a claim on behalf of a claimant may not contract for or receive from the claimant for services an amount greater than 10 percent of the paid claim.

Added by Acts 1993, 73rd Leg., ch. 515, Sec. 5, eff. Jan. 1, 1994. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 16, eff. Sept. 1, 2001. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.12, eff. September 28, 2011; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.13, eff. September 28, 2011.

Sec. 89.087. JUDICIAL REVIEW OF COMMISSION DECISIONS; IMMUNITY FROM SUIT AND LIABILITY. (a) A claimant aggrieved by the commission's decision on a claim may appeal the decision in a district court of Travis County on or before the 60th day after the date the decision was issued. If the commission does not decide a claim by the 90th day after the date it was filed, the claimant may appeal within the 60-day period beginning on the 91st day after the date of filing.

(b) Judicial review under this section is by trial de novo.

(c) No interest accrues on a claim before an appeal is filed under this section.

(d) Except to the extent permitted by this chapter, and notwithstanding any other provision of law, the commission, its employees or agents, and the State of Texas are immune from suit and from liability based on the disposition of well-site equipment or hydrocarbons in accordance with this chapter.

Added by Acts 1993, 73rd Leg., ch. 515, Sec. 5, eff. Jan. 1, 1994.

Sec. 89.088. RECORD OF REQUEST FOR NOTICE BY LIENHOLDER OR NONOPERATOR; FORM; FEE. (a) The commission shall maintain a record of a request for notice by a lienholder or nonoperator under Section 89.043(e) or 89.085(f) of this code for five years after the date on which the commission receives the request.

(b) The commission shall prepare a form for a request for notice. The commission shall require a person who requests notice to include on the form information that identifies the lease covered by the request.

(c) The commission may charge a filing fee for a request for notice not to exceed $10 for each lease covered by the request.

Added by Acts 1993, 73rd Leg., ch. 515, Sec. 5, eff. Jan. 1, 1994.

SUBCHAPTER E. ENFORCEMENT; JUDICIAL REVIEW

Sec. 89.121. ENFORCEMENT BY COMMISSION. (a) In addition to the powers specifically granted to the commission under this chapter, the commission may enforce this chapter or any rule or order of the commission adopted under this chapter in the same manner and on the same conditions as provided in the other chapters of Title 3 of this code.

(b) Civil penalties collected for violations of this chapter or of rules relating to plugging that are adopted under this code shall be deposited in the general revenue fund.

Acts 1977, 65th Leg., p. 2555, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983; Acts 1991, 72nd Leg., ch. 603, Sec. 7, eff. Sept. 1, 1991. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.14, eff. September 28, 2011.

Sec. 89.122. APPEAL TO COURTS. Any person affected by the provisions of this chapter may sue to test the validity of any order adopted by the commission under this chapter in the same manner, on the same conditions, and to the same court or courts as prescribed for suits testing the validity of orders of the commission adopted under the general oil conservation statutes of this state.

Acts 1977, 65th Leg., p. 2555, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

NATURAL RESOURCES CODE

TITLE 3. OIL AND GAS

SUBTITLE B. CONSERVATION AND REGULATION OF OIL AND GAS

CHAPTER 91. PROVISIONS GENERALLY APPLICABLE

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 91.001. DEFINITIONS. In this chapter:

(1) "Commission" means the Railroad Commission of Texas.

(2) "Gas" means natural gas.

(3) "Oil" means crude oil and crude petroleum oil.

Acts 1977, 65th Leg., p. 2560, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.002. CRIMINAL PENALTY. (a) A person who wilfully or with criminal negligence violates Section 91.101 of this code or a rule, order, or permit of the commission issued under that section commits an offense.

(b) An offense under Subsection (a) of this section is punishable by a fine of not more than $10,000 a day for each day a violation is committed.

(c) Venue for prosecution of an alleged violation of this section is in a court of competent jurisdiction in the county in which the violation is alleged to have occurred.

Added by Acts 1983, 68th Leg., p. 5262, ch. 967, Sec. 9, eff. Sept. 1, 1983. Renumbered from Sec. 91.351 by Acts 1987, 70th Leg., ch. 167, Sec. 5.01(a)(32), eff. Sept. 1, 1987.

Sec. 91.003. ADDITIONAL ENFORCEMENT AUTHORITY. (a) In addition to other authority specifically granted to the commission under this chapter, the commission may enforce this chapter or any rule, order, or permit of the commission adopted under this chapter in the manner and subject to the conditions provided in Chapters 81 and 85 of this code, including the authority to seek and obtain civil penalties and injunctive relief as provided by those chapters.

(b) If the enforcement authority in Section 81.054, Natural Resources Code, is used to institute a civil action alleging a violation of an NPDES permit issued under this chapter, the attorney general may not oppose intervention by a person who has standing to intervene as provided by Rule 60, Texas Rules of Civil Procedure.

Added by Acts 1983, 68th Leg., p. 5262, ch. 967, Sec. 9, eff. Sept. 1, 1983. Renumbered from Sec. 91.352 by Acts 1987, 70th

Leg., ch. 167, Sec. 5.01(a)(32), eff. Sept. 1, 1987. Amended by Acts 1995, 74th Leg., ch. 310, Sec. 6, eff. Aug. 28, 1995.

SUBCHAPTER B. DUTIES RELATING TO OIL AND GAS WELLS

Sec. 91.011. CASING. (a) Before drilling into the oil or gas bearing rock, the owner or operator of a well being drilled for oil or gas shall encase the well with good and sufficient wrought iron or steel casing or with any other material that meets standards adopted by the commission, particularly where wells could be subjected to corrosive elements or high pressures and temperatures, in a manner and to a depth that will exclude surface or fresh water from the lower part of the well from penetrating the oil or gas bearing rock, and if the well is drilled through the first into the lower oil or gas bearing rock, the well shall be cased in a manner and to a depth that will exclude fresh water above the last oil or gas bearing rock penetrated.

(b) The commission shall adopt rules regarding the depth of well casings necessary to meet the requirements of this section.

Acts 1977, 65th Leg., p. 2560, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1985, 69th Leg., ch. 704, Sec. 1, eff. Aug. 26, 1985. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.01, eff. September 1, 2011.

Sec. 91.0115. CASING; LETTER OF DETERMINATION. (a) The commission shall issue, on request from an applicant for a permit for a well to be drilled into oil or gas bearing rock, a letter of determination stating the total depth of surface casing required for the well by Section 91.011.

(b) The commission may charge a fee in an amount to be determined by the commission for a letter of determination.

(c) The commission shall charge a fee not to exceed $75, in addition to the fee required by Subsection (b), for processing a request to expedite a letter of determination.

(d) The fees collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.02, eff. September 1, 2011. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 835 (H.B. 7), Sec. 13, eff. June 14, 2013; Acts 2013, 83rd Leg., R.S., Ch. 1075 (H.B. 3309), Sec. 3, eff. September 1, 2013.

Sec. 91.012. WATER IN WELLS. (a) In boring any well for oil or gas, if a person pierces any cap rock or other geological formation in a manner that will cause a flow of salt water or fresh water injurious to an already bored oil well or any oil or gas deposits and that will probably result in the injury of the oil or gas field or already bored oil or gas well, the person shall abandon immediately all work on the well if the flow of water cannot be cased off and shall plug and fill the well in a manner and with materials that will stop the flow of the water.

(b) No well owner or person boring a well described under Subsection (a) of this section may remove the casing from the drilled well until the flow of water is stopped either by casing off or plugging the well.

(c) The provisions of this section apply only if the cap rock or other formation is pierced at a depth below the horizon at which oil or gas has been discovered already.

Acts 1977, 65th Leg., p. 2560, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.013. PLUGGING AND SHUTTING IN WELLS BY OTHERS. (a) If the owner of a well described in Subsection (a) of Section 91.012 of this code neglects or refuses to have the well plugged or shut in for more than 20 days after written notice is

given to him, the owner or operator of adjacent or neighboring land may enter the premises on which the well is located and have the well plugged if it is an abandoned well or shut in if it is not abandoned, in the manner provided by law.

(b) Notice may be given to the owner of the well either by personal service on the owner or by posting the notice at a conspicuous place at or near the well.

(c) The reasonable cost and expense incurred in plugging or shutting in the well shall be paid by the owner of the well and may be recovered as debts of like amount are recovered under the law.

Acts 1977, 65th Leg., p. 2560, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.014. PETITION TO RESTRAIN WASTE. (a) In addition to any other penalties, a district judge, in term time or vacation time, shall hear and determine any petition that is filed to restrain the waste of gas in violation of this subchapter and may issue mandatory or restraining orders that in his judgment are necessary.

(b) The petition may be filed by any citizen of this state and does not have to allege further financial interest of the petitioner in the state's natural resources than that possessed in common with all citizens of the state.

Acts 1977, 65th Leg., p. 2561, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.015. PREVENTION OF WASTE. Operators, contractors, drillers, pipeline companies, and gas distributing companies that drill for or produce oil or gas or pipe oil or gas for any purpose shall use every possible precaution in accordance with the most approved methods to stop and prevent waste of oil, gas, or both oil and gas in drilling and producing operations, storage, piping, and distribution and shall not wastefully use

oil or gas or allow oil or gas to leak or escape from natural reservoirs, wells, tanks, containers, or pipes.

Acts 1977, 65th Leg., p. 2561, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.016. CONFINING GAS TO ORIGINAL STRATUM. (a) If gas located in a gas-bearing stratum known to contain gas in paying quantities is encountered in a well drilled for oil or gas in this state, the gas shall be confined to its original stratum until it can be produced and used without waste.

(b) Gas-bearing strata shall be adequately protected from infiltrating water.

Acts 1977, 65th Leg., p. 2561, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.020. ELECTRONIC GEOLOGIC DATA. The commission shall work cooperatively with other appropriate state agencies to study and evaluate electronic access to geologic data and surface casing depths necessary to protect usable groundwater in this state.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.03, eff. September 1, 2011.

SUBCHAPTER C. STANDARD GAS MEASUREMENT

SUBCHAPTER D. PREVENTION OF POLLUTION

Sec. 91.101. RULES AND ORDERS.

Text of section effective until delegation of RCRA authority to Railroad Commission of Texas

(a) To prevent pollution of surface water or subsurface water in the state, the commission shall adopt and enforce rules and orders and may issue permits relating to:

(1) the drilling of exploratory wells and oil and gas wells or any purpose in connection with them;

(2) the production of oil and gas, including:

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

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

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

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

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

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

(3) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission; and

(4) the discharge, storage, handling, transportation, reclamation, or disposal of oil and gas waste as defined in Section 91.1011 of this subchapter, or of any other substance or material associated with any operation or activity regulated by

the commission under Subdivisions (1), (2), and (3) of this subsection.

(b) Notwithstanding the provisions of Subsection (a) of this section, the authority granted to the commission by this section does not include the authority to adopt and enforce rules and orders or issue permits regarding the collection, storage, handling, transportation, processing, or disposal of waste arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, 42 U.S.C. 6901 et seq., as amended.

Acts 1977, 65th Leg., p. 2563, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983; Acts 1985, 69th Leg., ch. 921, Sec. 4, eff. June 15, 1985.

Sec. 91.101. RULES AND ORDERS.

Text of section effective upon delegation of RCRA authority to Railroad Commission of Texas

To prevent pollution of surface water or subsurface water in the state, the commission shall adopt and enforce rules and orders and may issue permits relating to:

(1) the drilling of exploratory wells and oil and gas wells or any purpose in connection with them;

(2) the production of oil and gas, including:

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

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

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

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

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

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

(3) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission; and

(4) the discharge, storage, handling, transportation, reclamation, or disposal of oil and gas waste as defined in Section 91.1011 of this subchapter, or of any other substance or material associated with any operation or activity regulated by the commission under Subdivisions (1), (2), and (3) of this section.

Acts 1977, 65th Leg., p. 2563, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983; Acts 1985, 69th Leg., ch. 921, Sec. 4, eff. June 15, 1985.

Sec. 91.1011. OIL AND GAS WASTE.

Text of section effective until delegation of RCRA authority to Railroad Commission of Texas

(a) In this subchapter, "oil and gas waste" means waste that arises out of or incidental to the drilling for or producing of oil or gas, including waste arising out of or incidental to:

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

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

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

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

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

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

(b) "Oil and gas waste" includes salt water, brine, sludge, drilling mud, and other liquid, semiliquid, or solid waste material, but does not include waste arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure

maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, 42 U.S.C. 6901 et seq., as amended.

Added by Acts 1983, 68th Leg., p. 5060, ch. 967, Sec. 7, eff. Sept. 1, 1983. Amended by Acts 1985, 69th Leg., ch. 921, Sec. 4, eff. June 15, 1985.

Sec. 91.1011. OIL AND GAS WASTE.

Text of section effective upon delegation of RCRA authority to Railroad Commission of Texas

(a) In this subchapter, "oil and gas waste" means waste that arises out of or incidental to the drilling for or producing of oil or gas, including waste arising out of or incidental to:

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

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

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

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

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

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

(b) "Oil and gas waste" includes salt water, brine, sludge, drilling mud, and other liquid, semiliquid, or solid waste material.

Added by Acts 1983, 68th Leg., p. 5060, ch. 967, Sec. 7, eff. Sept. 1, 1983. Amended by Acts 1985, 69th Leg., ch. 921, Sec. 4, eff. June 15, 1985.

Sec. 91.1012. ACCESS TO PROPERTY AND RECORDS. Members and employees of the commission, on proper identification, may enter public or private property to inspect and investigate conditions relating to the quality of water in the state, to inspect and investigate conditions relating to development of rules, orders, or permits issuable under Section 91.101 of this code, to monitor compliance with a rule, permit, or other order of the commission, or to examine and copy, during reasonable working hours, those records or memoranda of the business being investigated. Members or employees acting under the authority of this section who enter an establishment on public or private property shall observe the establishment's safety, internal security, and fire protection rules.

Added by Acts 1983, 68th Leg., p 5260, ch. 967, Sec. 7, eff. Sept. 1, 1983.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 2122, 89th

Legislature, Regular Session, for amendments affecting the following section.

Sec. 91.1013. APPLICATION FEES. (a) With each application for a fluid injection well permit, the applicant shall submit to the commission a nonrefundable fee of $200. In this section, "fluid injection well" means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well regulated by the commission pursuant to Chapter 27, Water Code.

(b) With each application for a permit to discharge to surface water under this chapter and commission rules, other than a permit for a discharge that meets National Pollutant Discharge Elimination System requirements for agricultural or wildlife use, the applicant shall submit to the commission a nonrefundable fee of $300.

(c) Fees collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 1985, 69th Leg., ch. 239, Sec. 72, eff. Sept. 1, 1985. Amended by Acts 1991, 72nd Leg., ch. 603, Sec. 14, eff. Sept. 1, 1991; Acts 1999, 76th Leg., ch. 1089, Sec. 3, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 17, eff. Sept. 1, 2001. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.15, eff. September 28, 2011.

Sec. 91.1015. GROUNDWATER PROTECTION REQUIREMENTS. The commission shall adopt rules to establish groundwater protection requirements for operations that are within the jurisdiction of the commission, including requirements relating to the depth of surface casing for wells.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1021 (H.B. 2694), Sec. 2.04, eff. September 1, 2011.

Sec. 91.1017. LOCATION OF CERTAIN PITS. The commission by rule shall establish standards governing permissible locations for pits used by commercial oil and gas disposal facilities. The rules must include a history of flooding in the 10 years preceding the construction of the pit as a factor in determining whether a proposed location of a pit is permissible.

Added by Acts 2021, 87th Leg., R.S., Ch. 687 (H.B. 2201), Sec. 1, eff. September 1, 2021.

Sec. 91.102. ADDITIONAL PERSONNEL. The commission is directed to employ additional personnel necessary to administer this subchapter and related laws and rules and orders adopted by the commission.

Acts 1977, 65th Leg., p. 2563, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983.

Sec. 91.103. PERSONS REQUIRED TO EXECUTE BOND, LETTER OF CREDIT, OR CASH DEPOSIT.

Any person, including any firm, partnership, joint stock association, corporation, or other organization, required to file an organization report under Section 91. 142 of this code shall execute and file with the commission a bond, letter of credit, or cash deposit.

Acts 1977, 65th Leg., p. 2564, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983; Acts 1991, 72nd Leg., ch. 603, Sec. 8, eff. Sept. 1, 1991; Acts 2001, 77th Leg., ch. 1233, Sec. 18, eff. Sept. 1, 2004.

Sec. 91.104. BONDS, LETTERS OF CREDIT, CASH DEPOSITS, AND WELL-SPECIFIC PLUGGING INSURANCE POLICIES. (a) The commission

shall require a bond, letter of credit, or cash deposit to be filed with the commission as provided by Subsection (b).

(b) A person required to file a bond, letter of credit, or cash deposit under Section 91.103 who is an inactive operator or who operates one or more wells must, at the time of filing or renewing an organization report required by Section 91.142, file:

(1) an individual bond as provided under Section 91.1041;

(2) a blanket bond as provided under Section 91.1042; or

(3) a letter of credit or cash deposit in the same amount as required for an individual bond under Section 91.1041 or a blanket bond under Section 91.1042.

(c) A person required to file a bond, letter of credit, or cash deposit under Section 91.103 who operates one or more wells is considered to have met that requirement for a well if the well bore is included in a well-specific plugging insurance policy that:

(1) is approved by the Texas Department of Insurance;

(2) names this state as the owner and contingent beneficiary of the policy;

(3) names a primary beneficiary who agrees to plug the specified well bore;

(4) is fully prepaid and cannot be canceled or surrendered;

(5) provides that the policy continues in effect until the specified well bore has been plugged;

(6) provides that benefits will be paid when, but not before, the specified well bore has been plugged in accordance with commission rules in effect at the time of plugging; and

(7) provides benefits that equal the greatest of:

(A) an amount equal to $2 for each foot of well depth, as determined in the manner specified by the commission, for the specified well;

(B) if the specified well is a bay well and regardless of whether the well is producing oil or gas, the amount required under commission rules for a bay well that is not producing oil or gas;

(C) if the specified well is an offshore well and regardless of whether the well is producing oil or gas, the amount required under commission rules for an offshore well that is not producing oil or gas; or

(D) the payment otherwise due under the policy for plugging the well bore.

Acts 1977, 65th Leg., p. 2564, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983; Acts 1991, 72nd Leg., ch. 603, Sec. 9, eff. Sept. 1, 1991; Acts 1999, 76th Leg., ch. 30, Sec. 1, eff. Aug. 30, 1999; Acts 2001, 77th Leg., ch. 1233, Sec. 19, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1233, Sec. 20, eff. Sept. 1, 2004; Acts 2003, 78th Leg., ch. 490, Sec. 1, eff. Sept. 1, 2004. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 1, eff. June 17, 2005.

Sec. 91.1041. INDIVIDUAL BOND.

(a) A person required to file a bond, letter of credit, or cash deposit under Section 91.103 who operates one or more wells may file a bond in an amount equal to $2 for each foot of well depth for each well.

(b) Notwithstanding Subsection (a), the commission by rule shall set the amount of the bond for an operator of one or more bay or offshore wells at a reasonable amount that exceeds the amount provided by Subsection (a).

(c) When calculating under Subsection (a) the amount of the bond a person who operates one or more wells is required to file, the commission shall exclude a well if the well bore is included in a well-specific plugging insurance policy described by Section 91.104(c).

(d) If the inclusion of a bay or offshore well whose well bore is included in a well-specific plugging insurance policy described by Section 91.104(c) in the calculation under Subsection (b) of the amount of the bond an operator of one or more bay or offshore wells is required to file would result in an increase in the amount of the bond that would otherwise be required, the rules must provide for the exclusion of the well from the calculation.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 10, eff. Sept. 1, 1991. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 21, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1233, Sec. 22, eff. Sept. 1, 2004. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 2, eff. June 17, 2005.

Sec. 91.1042. BLANKET BOND.

(a) A person required to file a bond, letter of credit, or cash deposit under Section 91.103 may file a blanket bond to cover all wells for which a bond, letter of credit, or cash deposit is required as follows:

(1) a person who operates 10 or fewer wells shall file a $25,000 blanket bond;

(2) a person who operates more than 10 but fewer than 100 wells shall file a $50,000 blanket bond; and

(3) a person who operates 100 or more wells shall file a $250,000 blanket bond.

(b) Notwithstanding Subsection (a), the commission by rule shall set the amount of the bond for an operator of bay or offshore wells at a reasonable amount that exceeds the amount provided by Subsection (a)(1), (2), or (3), as applicable.

(c) When calculating the number of an operator's wells for purposes of Subsection (a), the commission shall exclude a well if the well bore is included in a well-specific plugging insurance policy described by Section 91.104(c).

(d) If the inclusion of a bay or offshore well whose well bore is included in a well-specific plugging insurance policy

described by Section 91.104(c) in the calculation under Subsection (b) of the amount of the bond an operator of bay or offshore wells is required to file would result in an increase in the amount of the bond that would otherwise be required, the rules must provide for the exclusion of the well from the calculation.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 10, eff. Sept. 1, 1991. Amended by Acts 2001, 77th Leg., ch. 1233, Sec. 23, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1233, Sec. 24, eff. Sept. 1, 2004. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 3, eff. June 17, 2005.

Sec. 91.105. BOND CONDITIONS. Each bond required by Section 91.103 shall be conditioned that the operator will plug and abandon all wells and control, abate, and clean up pollution associated with an operator's oil and gas activities covered under the bond in accordance with the law of the state and the permits, rules, and orders of the commission. This section does not apply to a well-specific plugging insurance policy described by Section 91.104(c).

Acts 1977, 65th Leg., p. 2563, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Renumbered from Sec. 91.106 by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983. Amended by Acts 1991, 72nd Leg., ch. 603, Sec. 11, eff. Sept. 1, 1991. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 4, eff. June 17, 2005.

Sec. 91.106. EXECUTION OF BOND. Each bond shall be executed by a corporate surety authorized to do business in this state and shall be renewed and be continued in effect until the conditions have been met or release is authorized by the commission.

Acts 1977, 65th Leg., p. 2564, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Renumbered from Sec. 91.107 by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983.

Sec. 91.107. NEW BOND, LETTER OF CREDIT, OR CASH DEPOSIT. If an active or inactive well is transferred, sold, or assigned by its operator, the commission shall require the party acquiring the well to file a new bond, letter of credit, or cash deposit as provided by Section 91.104(b), and the financial security of the prior operator shall continue to be required and to remain in effect, and the commission may not approve the transfer of operatorship, until the new bond, letter of credit, or cash deposit is provided or the commission determines that the bond, letter of credit, or cash deposit previously submitted to the commission by the person acquiring the well complies with this subchapter. A transfer of a well from one entity to another entity under common ownership is a transfer for purposes of this section. This section does not apply to a well bore that is included in a well-specific plugging insurance policy described by Section 91.104(c).

Acts 1977, 65th Leg., p. 2563, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Renumbered from Sec. 91.108 by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983. Amended by Acts 1991, 72nd Leg., ch. 603, Sec. 12, eff. Sept. 1, 1991; Acts 2001, 77th Leg., ch. 1233, Sec. 25, 26, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1233, Sec. 27, eff. Sept. 1, 2004. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 5, eff. June 17, 2005.

Sec. 91.108. DEPOSIT AND USE OF FUNDS. Subject to the refund provisions of Section 91.1091, if applicable, proceeds from bonds and other financial security required pursuant to this chapter and benefits under well-specific plugging insurance policies described by Section 91.104(c) that are paid to the

state as contingent beneficiary of the policies shall be deposited in the oil and gas regulation and cleanup fund and, notwithstanding Sections 81.068 and 91.113, may be used only for actual well plugging and surface remediation.

Added by Acts 1983, 68th Leg., p. 5258, ch. 967, Sec. 6, eff. Sept. 1, 1983. Amended by Acts 1991, 72nd Leg., ch. 603, Sec. 15, eff. Sept. 1, 1991; Acts 2001, 77th Leg., ch. 1233, Sec. 28, eff. Sept. 1, 2001. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 5, eff. June 17, 2005; Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.16, eff. September 28, 2011.

Sec. 91.109. FINANCIAL SECURITY FOR PERSONS INVOLVED IN ACTIVITIES OTHER THAN OPERATION OF WELLS. (a) A person applying for or acting under a commission permit to store, handle, treat, reclaim, or dispose of oil and gas waste may be required by the commission to maintain a performance bond or other form of financial security conditioned that the permittee will operate and close the storage, handling, treatment, reclamation, or disposal site in accordance with state law, commission rules, and the permit to operate the site. However, this section does not authorize the commission to require a bond or other form of financial security for saltwater disposal pits, emergency saltwater storage pits (including blow-down pits), collecting pits, or skimming pits provided that such pits are used in conjunction with the operation of an individual oil or gas lease. Subject to the refund provisions of Section 91.1091, proceeds from any bond or other form of financial security required by this section shall be placed in the oil and gas regulation and cleanup fund. Each bond or other form of financial security shall be renewed and continued in effect until the conditions have been met or release is authorized by the commission.

(b) In addition to the financial security requirements of Subsection (a), a person required to file a bond, letter of

credit, or cash deposit under Section 91.103 who is involved in activities other than the ownership or operation of wells must file the bond, letter of credit, or cash deposit at the time of filing or renewing an organization report required by Section 91.142 according to the following schedule:

(1) no bond, letter of credit, or cash deposit if the person is a:

(A) local distribution company;

(B) gas marketer;

(C) crude oil nominator;

(D) first purchaser;

(E) well servicing company;

(F) survey company;

(G) salt water hauler;

(H) gas nominator;

(I) gas purchaser; or

(J) well plugger; or

(2) a bond, letter of credit, or cash deposit in an amount not to exceed $25,000 if the person is involved in an activity that is not associated with the ownership or operation of wells and is not listed in Subdivision (1).

(c) A person who engages in more than one activity or operation, including well operation, for which a bond, letter of credit, or cash deposit is required under this subchapter is not required to file a separate bond, letter of credit, or cash deposit for each activity or operation in which the person is engaged. The person is required to file a bond, letter of credit, or cash deposit only in the amount required for the activity or operation in which the person engages for which a bond, letter of credit, or cash deposit in the greatest amount is required. The bond, letter of credit, or cash deposit filed covers all of the activities and operations for which a bond, letter of credit, or cash deposit is required under this subchapter.

Added by Acts 1985, 69th Leg., ch. 464, Sec. 1, eff. Aug. 26, 1985. Amended by Acts 1991, 72nd Leg., ch. 603, Sec. 17, eff. Sept. 1, 1991; Acts 2001, 77th Leg., ch. 1233, Sec. 29, eff. Sept. 1, 2004; Acts 2003, 78th Leg., ch. 490, Sec. 3, eff. Sept. 1, 2003. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.17, eff. September 28, 2011.

Sec. 91.1091. REFUND. The commission shall refund the proceeds from a bond, letter of credit, or cash deposit required under this subchapter if:

(1) the conditions that caused the proceeds to be collected are corrected;

(2) all administrative, civil, and criminal penalties relating to those conditions are paid; and

(3) the commission has been reimbursed for all costs and expenses incurred by the commission in relation to those conditions.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 16, eff. Sept. 1, 1991. Amended by Acts 1999, 76th Leg., ch. 30, Sec. 2, eff. Aug. 30, 1999. Amended by: Acts 2005, 79th Leg., Ch. 489 (H.B. 380), Sec. 5, eff. June 17, 2005.

Sec. 91.110. OIL AND GAS WASTE REDUCTION AND MINIMIZATION. To encourage the reduction and minimization of oil and gas waste, the commission shall implement a program to:

(1) provide operators with training and technical assistance on oil and gas waste reduction and minimization;

(2) assist operators in developing oil and gas waste reduction and minimization plans; and

(3) by rule establish incentives for oil and gas waste reduction and minimization.

Added by Acts 1991, 72nd Leg., ch. 296, Sec. 2.06, eff. June 7, 1991; Acts 1991, 72nd Leg., ch. 590, Sec. 6, eff. June 16, 1991.

Sec. 91.113. INVESTIGATION, ASSESSMENT, OR CLEANUP BY COMMISSION. (a) If oil and gas wastes or other substances or materials regulated by the commission under Section 91.101 are causing or are likely to cause the pollution of surface or subsurface water, the commission, through its employees or agents, may use money in the oil and gas regulation and cleanup fund to conduct a site investigation or environmental assessment or control or clean up the oil and gas wastes or other substances or materials if:

(1) the responsible person has failed or refused to control or clean up the oil and gas wastes or other substances or materials after notice and opportunity for hearing;

(2) the responsible person is unknown, cannot be found, or has no assets with which to control or clean up the oil and gas wastes or other substances or materials; or

(3) the oil and gas wastes or other substances or materials are causing the pollution of surface or subsurface water.

(b) For purposes of this section, "responsible person" means any operator or other person required by law, rules adopted by the commission, or a valid order of the commission to control or clean up the oil and gas wastes or other substances or materials.

(c) The commission or its employees or agents, on proper identification, may enter the land of another for the purpose of conducting a site investigation or environmental assessment or controlling or cleaning up oil and gas wastes or other substances or materials under this section.

(d) The conducting of a site investigation or environmental assessment or the control or cleanup of oil and gas wastes or other substances or materials by the commission under this section does not prevent the commission from seeking penalties or other relief provided by law from any person who is required by law, rules adopted by the commission, or a valid

order of the commission to control or clean up the oil and gas wastes or other substances or materials.

(e) The commission and its employees are not liable for any damages arising from an act or omission if the act or omission is part of a good-faith effort to carry out this section.

(f) If the commission conducts a site investigation or environmental assessment or controls or cleans up oil and gas wastes or other substances or materials under this section, the commission may recover all costs incurred by the commission from any person who was required by law, rules adopted by the commission, or a valid order of the commission to control or clean up the oil and gas wastes or other substances or materials. The commission by order may require the person to reimburse the commission for those costs or may request the attorney general to file suit against the person to recover those costs. At the request of the commission, the attorney general may file suit to enforce an order issued by the commission under this subsection. A suit under this subsection may be filed in any court of competent jurisdiction in Travis County. Costs recovered under this subsection shall be deposited to the oil and gas regulation and cleanup fund.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 1, eff. Sept. 1, 1991. Amended by Acts 1997, 75th Leg., ch. 120, Sec. 1, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 57, Sec. 3, eff. May 10, 1999. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.18, eff. September 28, 2011.

Sec. 91.1131. RISK ASSESSMENT STANDARDS. (a) The commission by rule may establish risk assessment as the guide for:

(1) conducting site investigations and environmental assessments; and

(2) controlling and cleaning up oil and gas wastes and other substances and materials.

(b) Rules adopted under this section must provide for:

(1) determining whether an actual or potential risk exists at a site;

(2) screening contaminants at the site to identify those that pose a risk;

(3) developing cleanup standards based on contamination levels that are protective of human health and the environment; and

(4) establishing a reporting mechanism for informing the commission regarding specific remediation activities.

Added by Acts 2001, 77th Leg., ch. 1233, Sec. 32, eff. Sept. 1, 2001.

Sec. 91.1132. PRIORITIZATION OF HIGH-RISK WELLS. The commission by rule shall develop a system for:

(1) identifying abandoned wells that pose a high risk of contaminating surface water or groundwater;

(2) periodically testing high-risk wells by conducting a fluid level test or, if necessary, a pressure test; and

(3) giving priority to plugging high-risk wells with compromised casings.

Added by Acts 2001, 77th Leg., ch. 1233, Sec. 32, eff. Sept. 1, 2001.

Sec. 91.114. ACCEPTANCE OF ORGANIZATION REPORT OR APPLICATION FOR PERMIT; APPROVAL OF CERTIFICATE OF COMPLIANCE; REVOCATION. (a) Except as provided by Subsection (d), the commission may not accept an organization report required under Section 91.142 or an application for a permit under this Chapter, Chapter 85, or Chapter 26, 27, or 29, Water Code, or approve a certificate of compliance under Section 91.701 if:

(1) the organization that submitted the report, application, or certificate violated a statute or commission

rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) a person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization and during that period of ownership or control the other organization violated a statute or commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(b) An organization has committed a violation if:

(1) a final judgment or final administrative order finding the violation has been entered against the organization and all appeals have been exhausted; or

(2) the commission and the organization have entered into an agreed order relating to the alleged violation.

(c) Regardless of whether the person's name appears or is required to appear on the organization report required by Section 91.142, a person holds a position of ownership or control in an organization if:

(1) the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of a sole proprietorship organization;

(D) the owner of at least 25 percent of the beneficial interest in the organization; or

(E) a trustee of the organization; or

(2) the person has been determined by a final judgment or final administrative order to have exerted actual control over the organization.

(d) The commission shall accept the report or application or approve the certificate if:

(1) the conditions that constituted the violation are corrected or are being corrected in accordance with a schedule to which the commission and the organization have agreed;

(2) all administrative, civil, and criminal penalties and all cleanup and plugging costs incurred by the state relating to those conditions are paid or are being paid in accordance with a payment schedule to which the commission and the organization have agreed; and

(3) the report, application, or certificate is in compliance with all other requirements of law and commission rules.

(e) If a report or application is rejected or a certificate is disapproved under this section, the commission shall provide the organization with a written statement explaining the reason for the rejection or disapproval.

(f) Notwithstanding Subsection (a), the commission may issue a permit to an organization described by Subsection (a) for a term specified by the commission if the permit is necessary to remedy a violation of law or commission rules.

(g) A fee tendered in connection with a report or application that is rejected under this section is nonrefundable.

(h) If the commission is prohibited by Subsection (a) from accepting an organization's organization report or application or approving the organization's certificate or would be prohibited from doing so by that subsection if the organization submitted a report, application, or certificate, the commission, after notice and opportunity for a hearing, by order may revoke:

(1) the organization's organization report filed under Section 91.142;

(2) a permit issued to the organization under this chapter, Chapter 85, or Chapter 26, 27, or 29, Water Code; or

(3) any certificate of compliance approved under Section 91.701.

(i) An order under Subsection (h) shall provide the organization a reasonable period of time to comply with the judgment or order finding the violation before the revocation takes effect.

(j) On revocation of its organization report, an organization may not perform any activities under the jurisdiction of the commission under this title or Chapter 26, 27, or 29, Water Code, except as necessary to remedy a violation of law or commission rules and as authorized by the commission.

(k) The commission may not revoke an organization's organization report, permit, or certificate of compliance under Subsection (h) if it finds that the organization has fulfilled the conditions set out in Subsection (d).

(l) In determining whether or not to revoke an organization's organization report, permit, or certificate of compliance under Subsection (h), the commission shall consider the organization's history of previous violations, the seriousness of previous violations, any hazard to the health or safety of the public, and the demonstrated good faith of the organization.

(m) Revocation of an organization's organization report, permit, or certificate does not relieve the organization of any existing or future duty under law, rules, or permit conditions to:

(1) protect surface or subsurface water from pollution;

(2) properly dispose of oil and gas waste; or

(3) clean up unpermitted discharges of oil and gas waste.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 13, eff. Sept. 1, 1991. Renumbered from Sec. 91.110 by Acts 1993, 73rd Leg., ch. 107, Sec. 10.01(10), eff. Aug. 30, 1993. Amended by Acts 1995, 74th Leg., ch. 617, Sec. 1, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 121, Sec. 1, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 30, Sec. 3, eff. Aug. 30, 1999; Acts 2003, 78th Leg., ch. 956, Sec. 1, eff. June 20, 2003. Amended by: Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 5, eff. September 1, 2007.

Sec. 91.115. FIRST LIEN ON EQUIPMENT AND STORED HYDROCARBONS OR DRILL CUTTINGS. (a) If a responsible person fails to clean up a site or facility that has ceased oil and gas operations under the commission's jurisdiction on or before the date the site or facility is required to be cleaned up by law or by a rule adopted or order issued by the commission, the state has a first lien, superior to all preexisting and subsequent liens and security interests, on the responsible person's interest in any hydrocarbons or drill cuttings stored at the site or facility and in any equipment that is:

(1) located at the site or facility; and

(2) used by the responsible person in connection with the activity that generated the pollution.

(b) The lien is in the amount of the total costs of cleaning up the oil and gas wastes or other substances from the site or facility and arises on the date the site or facility is required by law or by a rule or order of the commission to be cleaned up.

(c) The commission may foreclose on the lien by entering into a contract to clean up the site or facility. The commission is not required to give notice or an opportunity for a hearing to subordinate lienholders before entering into a contract to clean up the site or facility.

(d) The lien is extinguished if the site or facility is cleaned up in accordance with commission rules by any person before the commission enters into a contract to clean up the site or facility.

(e) The lien is extinguished as to any stored hydrocarbons or drill cuttings or items of equipment that are lawfully removed by any person other than the operator or a nonoperator according to a lien, lease, judgment, written contract, or security agreement before the commission enters into a cleanup contract. An item of equipment may not be removed from an abandoned site or facility if the removal will cause the release of a substance that may cause pollution unless the substance is lawfully disposed of.

(f) Equipment or stored hydrocarbons or drill cuttings subject to a lien under this section are presumed to have been abandoned on the date the commission enters into a contract to clean up the site or facility on which the equipment, hydrocarbons, or drill cuttings are located.

(f-1) The commission may dispose of the abandoned equipment or stored hydrocarbons in accordance with the provisions of Sections 89.085, 89.086, and 89.087 for the disposition of well-site equipment and hydrocarbons.

(f-2) The commission may dispose of the abandoned stored drill cuttings by contracting with a person to treat the drill cuttings at the site or facility for a subsequent beneficial use and selling the treated drill cuttings at a public auction or a public or private sale. Sections 89.085(c)-(i), 89.086, and 89.087 apply to the disposition of drill cuttings under this subsection in the same manner as those sections apply to the disposition of hydrocarbons.

(g) In this section:

(1) "Drill cuttings" has the meaning assigned by Section 123.001.

(2) "Responsible person" has the meaning assigned by Section 91.113.

(3) "Treat" means to use a manufacturing, mechanical, thermal, or chemical process other than sizing, shaping, diluting, or sorting.

(h) The lien provided by this section, as it relates to stored hydrocarbons, shall be subject to and inferior to any lien in favor of the State of Texas to secure royalty payments.

Added by Acts 1993, 73rd Leg., ch. 515, Sec. 7, eff. Jan. 1, 1994. Amended by Acts 2003, 78th Leg., ch. 1121, Sec. 1, 2, eff. Sept. 1, 2003. Amended by: Acts 2021, 87th Leg., R.S., Ch. 57 (S.B. 1260), Sec. 1, eff. May 18, 2021; Acts 2021, 87th Leg., R.S., Ch. 57 (S.B. 1260), Sec. 2, eff. May 18, 2021.

Sec. 91.116. NOTICE OF COMMERCIAL SURFACE DISPOSAL FACILITY PERMIT APPLICATION. (a) In this section, "commercial surface disposal facility" means a facility whose primary business purpose is to provide, for compensation, surface disposal of oil field fluids or oil and gas wastes, including land application for treatment and disposal.

(b) A person who files an application for a permit for a commercial surface disposal facility shall publish notice of the application in accordance with this section.

(c) The notice must include:

(1) the date the application was filed;

(2) a description of the location of the site for which the application was made, including the county in which the site is located, the name of the original survey and abstract number, and the direction and distance from the nearest municipality;

(3) the name of the owner of the site;

(4) the name of the applicant;

(5) the type of fluid or waste to be disposed of at the facility;

(6) the disposal method proposed; and

(7) the procedure for protesting the application.

(d) The notice must be published:

(1) at least once each week for two consecutive weeks with the first publication occurring not earlier than the date the application is filed and not later than the 30th day after the date on which the application is filed; and

(2) in a newspaper of general circulation in the county in which the proposed disposal would occur.

Added by Acts 1999, 76th Leg., ch. 668, Sec. 1, eff. Sept. 1, 1999.

Sec. 91.117. PUBLIC INFORMATION HEARING ON APPLICATION FOR COMMERCIAL SURFACE DISPOSAL FACILITY PERMIT. (a) In this

section, "commercial surface disposal facility" has the meaning assigned by Section 91.116.

(b) The commission may hold a public meeting to receive public comment on an application for a commercial surface disposal facility if the commission determines a public meeting is in the public interest.

(c) The meeting must be held in the county in which the proposed facility would be located.

Added by Acts 1999, 76th Leg., ch. 668, Sec. 1, eff. Sept. 1, 1999.

SUBCHAPTER E. BOOKS, RECORDS, AND REPORTS

Sec. 91.141. BOOKS AND RECORDS. (a) Owners and operators of oil and gas wells shall keep books that show accurately:

(1) the amount of sold and unsold stock;

(2) the amount of promotion money paid;

(3) the amount of oil and gas produced and disposed of and the price for which the oil and gas was sold;

(4) the receipts from the sale or transfer of leases or other property; and

(5) disbursements made in connection with or for the benefit of the business.

(b) The books shall be kept open for the inspection of the commission or any accredited representative of the commission and any stockholder or shareholder or royalty owner in the business.

(c) The owners and operators of oil and gas wells shall report the information to the commission for its information if required by the commission to do so.

Acts 1977, 65th Leg., p. 2564, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977.

Sec. 91.142. REPORT TO COMMISSION. (a) A person, firm, partnership, joint stock association, corporation, or other domestic or foreign organization operating wholly or partially in this state and acting as principal or agent for another for the purpose of performing operations which are within the jurisdiction of the commission shall file immediately with the commission:

(1) the name of the company or organization;

(2) the post-office address of the company or organization;

(3) the plan under which the company or organization was organized;

(4) the names and post-office addresses of the trustee or trustees of the company or organization;

(5) the names, unique identifying numbers such as driver's license numbers, and post-office addresses of the officers and directors; and

(6) if required by Subsection (b) of this section, the name and address of the resident agent.

(b) Any foreign or nonresident entity listed in Subsection (a) of this section shall maintain or designate a resident agent upon whom any process, notice, or demand required or permitted by law to be served upon such entity may be served.

(c) If any such entity required by the terms of this section to maintain or designate such agent shall fail to do so, then and in such event, the organization report required to be filed with the commission is not valid.

(d) Failure by any such entity listed in Subsection (a) of this section to answer such process or demand shall render the organization report invalid.

(e) The commission shall require an entity described by Subsection (a) of this section to refile an organization report annually according to a schedule established by the commission.

(f) If an entity described by Subsection (a) does not maintain on file with the commission an organization report and financial security as required by this chapter:

(1) the entity may not perform operations under the jurisdiction of the commission except as necessary to remedy a violation of law or commission rules and as authorized by the commission; and

(2) the commission, on written notice, may suspend:

(A) any permits held by the entity; or

(B) any certificates of compliance approved under Subchapter P.

(g) An organization report filed under this section must be accompanied by the following fee:

(1) for an operator of not more than 25 wells, $300;

(2) for an operator of more than 25 but not more than 100 wells, $500;

(3) for an operator of more than 100 wells, $1,000;

(4) for an operator of one or more natural gas pipelines as classified by the commission, $225;

(5) for an operator of one or more service activities or facilities who does not operate any wells, an amount determined by the commission but not less than $300 or more than $500;

(6) for an operator of one or more liquids pipelines as classified by the commission who does not operate any wells, an amount determined by the commission but not less than $425 or more than $625;

(7) for an operator of one or more service activities or facilities, including liquids pipelines as classified by the commission, who also operates one or more wells, an amount determined by the commission based on the sum of the amounts provided by the applicable subdivisions of this subsection but not less than $425 or more than $1,125; and

(8) for an entity not currently performing operations under the jurisdiction of the commission, $300.

(h) To enable the commission to better protect the state's resources, an entity described by Subsection (a) or an affiliate of such an entity performing operations within the jurisdiction of the commission that files for federal bankruptcy protection

shall give written notice to the commission of that action by submitting the notice to the office of general counsel not later than the 30th day after the date of filing.

Acts 1977, 65th Leg., p. 2565, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1985, 69th Leg., ch. 398, Sec. 1, eff. Aug. 26, 1985; Acts 1997, 75th Leg., ch. 121, Sec. 2, eff. Sept. 1, 1997; Acts 2001, 77th Leg., ch. 1233, Sec. 33, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 490, Sec. 4, eff. Sept. 1, 2003; Acts 2003, 78th Leg., ch. 626, Sec. 1, eff. Sept. 1, 2003. Amended by: Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 6, eff. September 1, 2007.

Sec. 91.143. FALSE APPLICATIONS, REPORTS, AND DOCUMENTS AND TAMPERING WITH GAUGES. (a) A person may not:

(1) make or subscribe any application, report, or other document required or permitted to be filed with the commission by the provisions of Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, knowing that the application, report, or other document is false or untrue in a material fact;

(2) aid or assist in, or procure, counsel, or advise the preparation or presentation of any of these applications, reports, or other documents that are fraudulent, false, or incorrect in any material matter, knowing them to be fraudulent, false, or incorrect in any material matter;

(3) knowingly simulate or falsely or fraudulently execute or sign such an application, report, or other document;

(4) knowingly procure these applications, reports, or other documents to be falsely or fraudulently executed, or advise, aid in, or connive at this execution; or

(5) knowingly render inaccurate any monitoring device required to be maintained by a commission rule, order, or permit.

(b) A person commits an offense if the person violates this section. An offense under this section is a felony punishable by:

(1) imprisonment in the Texas Department of Criminal Justice for a term of not less than two years or more than five years;

(2) a fine of not more than $10,000; or

(3) both the imprisonment and the fine.

(c) If other penalties prescribed in Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, overlap offenses that are also punishable under this section, the penalties prescribed in this section shall be in addition to other penalties.

(d) No application, report, or other document required or permitted to be filed with the commission under Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, may be required to be under oath, verification, acknowledgment, or affirmation.

(e) The commission may impose an administrative penalty in the manner provided by Sections 81.0531-81.0534 on a person who violates this section. The amount of the penalty may not exceed $1,000 for each violation.

Acts 1977, 65th Leg., p. 2565, ch. 871, art. I, Sec. 1, eff. Sept. 1, 1977. Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, Sec. 1, eff. Sept. 1, 1983; Acts 1999, 76th Leg., ch. 31, Sec. 1, eff. Aug. 30, 1999. Amended by: Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 25.136, eff. September 1, 2009.

SUBCHAPTER F. UNDERGROUND NATURAL GAS STORAGE AND CONSERVATION

SUBCHAPTER G. UNDERGROUND HYDROCARBON STORAGE

SUBCHAPTER H. UNDERGROUND STORAGE FACILITIES FOR NATURAL GAS

SUBCHAPTER J. PAYMENT FOR PROCEEDS OF SALE

SUBCHAPTER K. SALTWATER DISPOSAL PITS

SUBCHAPTER L. ROYALTY REPORTING STANDARDS

SUBCHAPTER M. ELECTRIC LOGS

Sec. 91.551. DEFINITIONS. (a) In this subchapter:

(1) "Well" means a well drilled for any purpose related to exploration for or production or storage of oil or gas or both oil and gas, including a well drilled for injection of fluids to enhance hydrocarbon recovery, disposal of produced fluids, disposal of waste from exploration or production activity, or brine mining.

(2) "Electric log" means a wireline survey, except dipmeter surveys and seismic wireline surveys, run in an open hole or a cased hole of a well for purposes of obtaining geological information.

(3) "Drilling operation" means a continuous effort to drill or deepen a well bore for which the commission has issued a permit.

(4) "Operator" means a person who assumes responsibility for the regulatory compliance of a well as shown by a form the person files with the commission and the commission approves.

(b) In this subchapter, "operator" includes a predecessor or successor operator.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985. Amended by: Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 1, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 2, eff. September 1, 2005.

Sec. 91.552. ELECTRIC LOGS REQUIRED TO BE FILED; CRITERIA. (a) Except as otherwise provided by this subchapter, not later

than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a copy of each electric log, including each borehole section of the log at all depths, run after September 1, 2013, in conjunction with the drilling or deepening of the well that meets basic criteria established by the commission. Each electric log must be filed with the commission electronically in a manner acceptable to the commission if the commission has the technological capability to receive the electronic filing.

(b) The commission by rule shall establish criteria for electric logs to be filed with the commission.

(c) Not later than the deadline prescribed by Subsection (a) for the filing of each electric log, an operator shall file with the commission a copy of a cased hole log run after September 1, 2013, in conjunction with the drilling or deepening of a well in lieu of an electric log run after that date if:

(1) a cased hole log was run; and

(2) an electric log was not run.

(d) Nothing in this subchapter requires an operator to run an electric log in conjunction with the drilling or deepening of a well.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985. Amended by: Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 3, eff. September 1, 2005; Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 1, eff. September 1, 2013.

Sec. 91.553. AVAILABILITY OF ELECTRIC LOGS. (a) Except as specifically provided by this section, each electric log filed with the commission under this subchapter is not confidential and is public information under Chapter 552, Government Code.

(b) Not later than the date by which an electric log is required to be filed with the commission under Section 91.552, the operator may file a written request with the commission asking that the electric log remain confidential and not be made

available as public information. On filing this request, the electric log or copy of the electric log required to be filed with the commission may be retained by the operator, and the electric log may remain in the possession of the operator for the period of confidentiality. On filing of the request for confidentiality, the electric log becomes confidential and remains confidential for a period of:

(1) three years after the date that the drilling operation was completed, if the well is an onshore well; or

(2) five years after the date that the drilling operation was completed, if the well is a bay or offshore well.

(c) Repealed by Acts 2013, 83rd Leg., R.S., Ch. 279, Sec. 6, eff. September 1, 2013.

(d) Repealed by Acts 2013, 83rd Leg., R.S., Ch. 279, Sec. 6, eff. September 1, 2013.

(e) An operator required to file an electric log under this section who has held the log during a period of confidentiality shall file the log with the commission within 30 days after the conclusion of the period of confidentiality.

(f) An operator who fails to timely file with the commission a written request under Subsection (b) that an electric log remain confidential and not be made available as public information shall file the log with the commission immediately after the conclusion of the period for filing the request.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985. Amended by Acts 1995, 74th Leg., ch. 76, Sec. 5.95(90), eff. Sept. 1, 1995. Amended by: Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 4, eff. September 1, 2005; Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 2, eff. September 1, 2013; Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 6, eff. September 1, 2013.

Sec. 91.554. AVAILABILITY OF CONFIDENTIAL ELECTRIC LOGS. If the commission requires an electric log to be filed before

the expiration of a period of confidentiality, the commission shall make that electric log available for inspection during the period of confidentiality only to:

(1) a person authorized in writing by the operator; and

(2) members of the commission and its employees in the exercise of their powers and duties under this code.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985. Amended by: Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 5, eff. September 1, 2005.

Sec. 91.555. MANAGEMENT AND STORAGE OF ELECTRIC LOGS. The commission may contract with any person for the management and storage of the electric logs filed with the commission.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985.

Sec. 91.556. ENFORCEMENT. If an operator fails to file an electric log as required by this subchapter, the commission may:

(1) if the well is completed as a producing well, refuse to assign an allowable or a change in allowable for production from the well for which the electric log is required until the operator files the electric log with the commission; or

(2) impose an administrative penalty on the operator in the manner provided by Sections 81.0531-81.0534 for each well for which the operator failed to file an electric log.

Added by Acts 1985, 69th Leg., ch. 978, Sec. 1, eff. Sept. 1, 1985. Amended by: Acts 2005, 79th Leg., Ch. 1001 (H.B. 484), Sec. 5, eff. September 1, 2005; Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 3, eff. September 1, 2013.

SUBCHAPTER N. OIL AND GAS HAZARDOUS WASTE

Sec. 91.601. DEFINITIONS. In this subchapter:

(1) "Oil and gas hazardous waste" means oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. Section 6901 et seq.).

(2) "Oil and gas waste" means oil and gas waste as defined in Section 91.1011 of this chapter.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 20, eff. Sept. 1, 1991.

Sec. 91.602. RULES. (a) To protect human health and the environment, the commission shall adopt and enforce rules and orders and may issue permits relating to the generation, transportation, treatment, storage, and disposal of oil and gas hazardous waste.

(b) The rules adopted by the commission under this section must be consistent with the hazardous waste regulations adopted by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. Section 6901 et seq.). The commission may adopt and enforce rules that are more stringent than the federal hazardous waste regulations if necessary to protect human health.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 20, eff. Sept. 1, 1991.

Sec. 91.603. ACCESS TO PROPERTY AND RECORDS. (a) A member or employee of the commission, on proper identification, may enter public or private property to:

(1) inspect and investigate conditions relating to the generation, transportation, treatment, storage, or disposal of oil and gas hazardous waste;

(2) inspect and investigate conditions relating to the development of rules, orders, or permits under Section 91.602 of this code;

(3) monitor compliance with a rule, order, or permit of the commission; or

(4) examine and copy, during reasonable working hours, those records or memoranda of the business being investigated.

(b) A member or employee acting under this section who enters an establishment on public or private property shall observe the establishment's posted safety, internal security, and fire protection rules.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 20, eff. Sept. 1, 1991.

Sec. 91.604. CRIMINAL PENALTY. (a) A person who knowingly violates a rule, order, or permit of the commission issued under this subchapter commits an offense.

(b) An offense under this section is punishable by imprisonment for up to six months, by a fine of up to $10,000 for each day the violation is committed, or by both.

(c) Venue for prosecution under this section is in the county in which the violation is alleged to have occurred.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 20, eff. Sept. 1, 1991.

Sec. 91.605. HAZARDOUS OIL AND GAS WASTE GENERATION FEE. (a) An annual fee is imposed on each operator who generates hazardous oil and gas waste.

(b) The commission by rule shall set the fee, which must:

(1) be based on the volume of hazardous oil and gas waste generated by the operator; and

(2) be reasonably related to the costs of implementing this subchapter and enforcing the rules, orders, and permits adopted or issued by the commission under this subchapter.

(c) The commission by rule shall also prescribe the procedures by which an operator must account for the volume of hazardous oil and gas waste generated and pay the fee.

(d) This section does not apply to an operator who, at all facilities operated in this state, satisfies the requirements established by the administrator of the United States Environmental Protection Agency for a conditionally exempt small quantity generator.

(e) The fees collected under this section shall be deposited in the oil and gas regulation and cleanup fund.

Added by Acts 1991, 72nd Leg., ch. 603, Sec. 20, eff. Sept. 1, 1991. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.22, eff. September 28, 2011.

SUBCHAPTER O. RAILROAD COMMISSION VOLUNTARY CLEANUP PROGRAM

SUBCHAPTER P. CERTIFICATE OF COMPLIANCE

Sec. 91.701. WELL OWNERS AND OPERATORS CERTIFICATES. The owner or operator of any well subject to the jurisdiction of the commission under this title, Section 26.131, Water Code, or Subchapter C, Chapter 27, Water Code, shall secure from the commission a certificate showing compliance with that title, section, or subchapter, as applicable, rules adopted and orders issued under that title, section, or subchapter, as applicable, and any license, permit, or certificate issued to the owner or operator under that title, section, or subchapter, as applicable.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.702. PROHIBITED CONNECTION. No operator of a pipeline or other carrier shall connect with any well subject to the jurisdiction of the commission under this title, Section 26.131, Water Code, or Subchapter C, Chapter 27, Water Code, until the owner or operator of the well furnishes a certificate from the commission that the owner or operator has complied with that title, section, or subchapter, as applicable, rules adopted and orders issued under that title, section, or subchapter, as applicable, and any license, permit, or certificate issued to the owner or operator under that title, section, or subchapter, as applicable.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.703. TEMPORARY CONNECTION. The provisions of this subchapter do not prevent a temporary connection with a well in order to take care of production and prevent waste until opportunity shall have been given the owner or operator of the well to secure the certificate.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.704. CANCELLATION OF CERTIFICATE. The commission may cancel any certificate of compliance issued under the provisions of this subchapter if it appears that the owner or operator of a well covered by the provisions of the certificate, in the operation of the well or the production of oil or gas

from the well, has violated or is violating this title, Section 26.131, Water Code, or Subchapter C, Chapter 27, Water Code, a rule adopted or order issued under that title, section, or subchapter, as applicable, or a license, permit, or certificate issued to the owner or operator under that title, section, or subchapter, as applicable. Before canceling a certificate of compliance, the commission shall give notice to the owner or operator by personal service or by registered or certified mail of the facts or conduct alleged to warrant the cancellation and shall give the owner or operator an opportunity to show compliance with all requirements of law for retention of the certificate as required by Section 2001.054, Government Code.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.705. EFFECT OF CANCELLATION ON OPERATOR OF PIPELINE OR OTHER CARRIER. (a) On notice from the commission to the operator of a pipeline or other carrier connected to a well that the certificate of compliance pertaining to that well has been cancelled, the operator of the pipeline or other carrier shall disconnect from the well.

(b) It shall be unlawful for the operator of a pipeline or other carrier to reconnect to the well until a new certificate of compliance has been issued by the commission.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.706. EFFECT OF CANCELLATION ON OWNER OR OPERATOR OF WELL. (a) On notice from the commission that a certificate of compliance for a well has been cancelled, it shall be unlawful for the owner or operator of the well to use the well for production, injection, or disposal until a new certificate

of compliance covering the well has been issued by the commission.

(b) If an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been cancelled, the commission may refuse to renew the operator's organization report required by Section 91.142 until the operator pays the fee required by Section 91.707 and the commission issues the certificate of compliance required for that well.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007.

Sec. 91.707. FEE FOR REISSUED CERTIFICATE. (a) If a certificate of compliance for a well has been canceled for one or more violations of provisions of this title, Section 26.131, Water Code, or Subchapter C, Chapter 27, Water Code, rules adopted or orders issued under that title, section, or subchapter, as applicable, or licenses, permits, or certificates issued to the owner or operator of the well under that title, section, or subchapter, as applicable, the commission may not issue a new certificate of compliance until the owner or operator submits to the commission a nonrefundable fee of $300 for each severance or seal order issued for the well.

(b) Fees collected under this section shall be deposited to the oil and gas regulation and cleanup fund.

Redesignated from Natural Resources Code, Subchapter E, Chapter 85 and amended by Acts 2007, 80th Leg., R.S., Ch. 816 (S.B. 1670), Sec. 1, eff. September 1, 2007. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 19.24, eff. September 28, 2011.

SUBCHAPTER Q. NOTICE OF PERMIT FOR CERTAIN OIL AND GAS OPERATIONS

Sec. 91.751. DEFINITION. In this subchapter, "surface owner" means the first person who is shown on the appraisal roll of the appraisal district established for the county in which a tract of land is located as owning an interest in the surface estate of the land at the time notice is required to be given under this subchapter.

Added by Acts 2007, 80th Leg., R.S., Ch. 210 (H.B. 630), Sec. 1, eff. September 1, 2007.
Renumbered from Natural Resources Code, Section 91.701 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(71), eff. September 1, 2009.

Sec. 91.752. APPLICABILITY. This subchapter applies only to the drilling of a new oil or gas well or the reentry of a plugged and abandoned oil or gas well. This subchapter does not apply to:

(1) the plugging back, reworking, sidetracking, or deepening of an existing oil or gas well that has not been plugged and abandoned; or

(2) the use of a surface location that is the site of an existing oil or gas well that has not been plugged and abandoned to drill a horizontal oil or gas well.

Added by Acts 2007, 80th Leg., R.S., Ch. 210 (H.B. 630), Sec. 1, eff. September 1, 2007. Renumbered from Natural Resources Code, Section 91.702 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(71), eff. September 1, 2009.

Sec. 91.753. NOTICE REQUIRED. (a) Not later than the 15th business day after the date the commission issues an oil or gas well operator a permit to drill a new oil or gas well or to reenter a plugged and abandoned oil or gas well, the operator shall give written notice of the issuance of the permit to the

surface owner of the tract of land on which the well is located or is proposed to be located.

(b) An oil or gas well operator is not required to give notice under this subchapter to a surface owner if:

(1) the operator and the surface owner have entered into an agreement that contains alternative provisions regarding the operator's obligation to give notice of oil and gas operations; or

(2) the surface owner has waived in writing the owner's right to notice under this subchapter.

Added by Acts 2007, 80th Leg., R.S., Ch. 210 (H.B. 630), Sec. 1, eff. September 1, 2007. Renumbered from Natural Resources Code, Section 91.703 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(71), eff. September 1, 2009.

Sec. 91.754. ADDRESS FOR NOTICE. The notice must be given to the surface owner at the surface owner's address as shown by the records of the county tax assessor-collector at the time the notice is given.

Added by Acts 2007, 80th Leg., R.S., Ch. 210 (H.B. 630), Sec. 1, eff. September 1, 2007. Renumbered from Natural Resources Code, Section 91.704 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(71), eff. September 1, 2009.

Sec. 91.755. COMMISSION PERMITS AND RIGHTS OF OWNER OF MINERAL ESTATE NOT AFFECTED. (a) This subchapter does not affect the status of any rule of law to the effect that the mineral estate in land is dominant over the surface estate.

(b) Failure to give notice as required by this subchapter does not restrict, limit, work as a forfeiture of, or terminate any existing or future permit issued by the commission or right to develop the mineral estate in land.

Added by Acts 2007, 80th Leg., R.S., Ch. 210 (H.B. 630), Sec. 1, eff. September 1, 2007. Renumbered from Natural Resources Code, Section 91.705 by Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(71), eff. September 1, 2009.

SUBCHAPTER R. AUTHORIZATION FOR MULTIPLE OR ALTERNATIVE USES OF WELLS

Sec. 91.801. RULES AUTHORIZING MULTIPLE OR ALTERNATIVE USES OF WELLS. The commission shall adopt rules allowing:

(1) a person to obtain a permit for a well from the commission that authorizes the well to be used for multiple purposes; and

(2) an operator of a well authorized by a permit issued by the commission to convert the well from its authorized purpose to a new or additional purpose.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 6, eff. September 1, 2009.

Sec. 91.802. LAW APPLICABLE TO GEOLOGIC STORAGE FACILITIES AND ASSOCIATED INJECTION WELLS. (a) In this section, "anthropogenic carbon dioxide injection well" has the meaning assigned by Section 27.002, Water Code.

(b) If a well is authorized as or converted to an anthropogenic carbon dioxide injection well for geologic storage, Subchapter C-1, Chapter 27, Water Code, applies to the well.

(c) A conversion of an anthropogenic carbon dioxide injection well from use for enhanced recovery operations to use for geologic storage is not considered to be a change in the purpose of the well.

Added by Acts 2009, 81st Leg., R.S., Ch. 224 (S.B. 1387), Sec. 6, eff. September 1, 2009.

SUBCHAPTER S. DISCLOSURE OF COMPOSITION OF HYDRAULIC FRACTURING FLUIDS

Sec. 91.851. DISCLOSURE OF COMPOSITION OF HYDRAULIC FRACTURING FLUIDS. (a) The commission by rule shall:

(1) require an operator of a well on which a hydraulic fracturing treatment is performed to:

(A) complete the form posted on the hydraulic fracturing chemical registry Internet website of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission with regard to the well;

(B) include in the form completed under Paragraph (A):

(i) the total volume of water used in the hydraulic fracturing treatment; and

(ii) each chemical ingredient that is subject to the requirements of 29 C.F.R. Section 1910.1200(g)(2), as provided by a service company or chemical supplier or by the operator, if the operator provides its own chemical ingredients;

(C) post the completed form described by Paragraph (A) on the website described by that paragraph or, if the website is discontinued or permanently inoperable, post the completed form on another publicly accessible Internet website specified by the commission;

(D) submit the completed form described by Paragraph (A) to the commission with the well completion report for the well; and

(E) in addition to the completed form specified in Paragraph (D), provide to the commission a list, to be made available on a publicly accessible website, of all other chemical ingredients not listed on the completed form that were intentionally included and used for the purpose of creating a hydraulic fracturing treatment for the well. The commission rule shall ensure that an operator, service company, or supplier is not responsible for disclosing ingredients that:

(i) were not purposely added to the hydraulic fracturing treatment;

(ii) occur incidentally or are otherwise unintentionally present in the treatment; or

(iii) in the case of the operator, are not disclosed to the operator by a service company or supplier. The commission rule shall not require that the ingredients be identified based on the additive in which they are found or that the concentration of such ingredients be provided;

(2) require a service company that performs a hydraulic fracturing treatment on a well or a supplier of an additive used in a hydraulic fracturing treatment on a well to provide the operator of the well with the information necessary for the operator to comply with Subdivision (1);

(3) prescribe a process by which an entity required to comply with Subdivision (1) or (2) may withhold and declare certain information as a trade secret for purposes of Section 552.110, Government Code, including the identity and amount of the chemical ingredient used in a hydraulic fracturing treatment;

(4) require a person who desires to challenge a claim of entitlement to trade secret protection under Subdivision (3) to file the challenge not later than the second anniversary of the date the relevant well completion report is filed with the commission;

(5) limit the persons who may challenge a claim of entitlement to trade secret protection under Subdivision (3) to:

(A) the landowner on whose property the relevant well is located;

(B) a landowner who owns property adjacent to property described by Paragraph (A); or

(C) a department or agency of this state with jurisdiction over a matter to which the claimed trade secret is relevant;

(6) require, in the event of a trade secret challenge, that the commission promptly notify the service

company performing the hydraulic fracturing treatment on the relevant well, the supplier of the additive or chemical ingredient for which the trade secret claim is made, or any other owner of the trade secret being challenged and provide the owner an opportunity to substantiate its trade secret claim; and

(7) prescribe a process, consistent with 29 C.F.R. Section 1910.1200, for an entity described by Subdivision (1) or (2) to provide information, including information that is a trade secret as defined by Appendix D to 29 C.F.R. Section 1910.1200, to a health professional or emergency responder who needs the information in accordance with Subsection (i) of that section.

(b) The protection and challenge of trade secrets under this section is governed by Chapter 552, Government Code.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1179 (H.B. 3328), Sec. 1, eff. September 1, 2011.

SUBCHAPTER T. SALTWATER PIPELINES

Sec. 91.901. DEFINITIONS. In this subchapter:

(1) "Saltwater pipeline facility" means a pipeline facility that conducts water that contains salt and other substances and is intended to be used in drilling or operating a well used in the exploration for or production of oil or gas, including an injection well used for enhanced recovery operations, or is produced during drilling or operating an oil, gas, or other type of well. The term includes a pipeline facility that conducts flowback and produced water from an oil or gas well on which a hydraulic fracturing treatment has been performed to an oil and gas waste disposal well for disposal.

(2) "Saltwater pipeline operator" means a person who owns, installs, manages, operates, leases, or controls a saltwater pipeline facility.

Added by Acts 2013, 83rd Leg., R.S., Ch. 1408 (S.B. 514), Sec. 1, eff. June 14, 2013. Amended by: Acts 2015, 84th Leg., R.S., Ch. 389 (H.B. 497), Sec. 1, eff. June 10, 2015.

Sec. 91.902. PIPELINE ON PUBLIC ROAD. A saltwater pipeline operator is entitled to install, maintain, and operate a saltwater pipeline facility through, under, along, across, or over a public road only if:

(1) the pipeline facility complies with applicable rules adopted by the Texas Transportation Commission and applicable county and municipal regulations regarding the accommodation of utility facilities on a public road or right-of-way, including regulations relating to the horizontal or vertical placement of the pipeline facility;

(2) the saltwater pipeline operator ensures that the public road and associated facilities are promptly restored to their former condition of usefulness after the installation or maintenance of the pipeline facility is complete; and

(3) the saltwater pipeline operator leases the right-of-way or area in which the pipeline facility is installed and pays to the applicable governmental entity the fair market value of the operator's use of the right-of-way or area, unless the operator is authorized by other law to install, maintain, and operate the pipeline facility through, under, along, across, or over the public road.

Added by Acts 2013, 83rd Leg., R.S., Ch. 1408 (S.B. 514), Sec. 1, eff. June 14, 2013.

Sec. 91.903. RELOCATION OF SALTWATER PIPELINE FACILITY FOR CERTAIN PURPOSES. (a) Except as provided by Section 203.092, Transportation Code, the Texas Transportation Commission, the commissioners court of a county, or the governing body of a municipality, as applicable, may require a saltwater pipeline operator to relocate a saltwater pipeline facility at the cost

of the saltwater pipeline operator to accommodate construction or expansion of a public road or for any other public work unless the saltwater pipeline operator has a property interest in the land occupied by the facility to be relocated.

(b) The Texas Transportation Commission, the commissioners court of a county, or the governing body of a municipality, as applicable, shall give to the saltwater pipeline operator 30 days' written notice of the requirement. The notice must identify the pipeline facility to be relocated and indicate the approximate location on the new right-of-way where the saltwater pipeline operator may place the facility.

Added by Acts 2013, 83rd Leg., R.S., Ch. 1408 (S.B. 514), Sec. 1, eff. June 14, 2013.

Sec. 91.904. CONSTRUCTION OF SUBCHAPTER. This subchapter may not be construed to:

(1) limit the authority of a saltwater pipeline facility to use a public right-of-way under any other law;

(2) affect the authority of a municipality to:

(A) regulate the use of a public right-of-way by a saltwater pipeline operator under any other law; or

(B) require payment of any applicable charge under Section 182.025, Tax Code; or

(3) require a county or municipality to:

(A) grant a right to a saltwater pipeline operator that applies to a public road or right-of-way and that is broader than the county's or municipality's legal interest in the public road or right-of-way; or

(B) grant more than a surface right to a saltwater pipeline operator in a right-of-way acquired by prescription.

Added by Acts 2013, 83rd Leg., R.S., Ch. 1408 (S.B. 514), Sec. 1, eff. June 14, 2013.

Sec. 91.905. APPLICATION OF OTHER LAW. Section 212.153(e), Local Government Code, and Sections 203.092 and 224.008, Transportation Code, apply to saltwater pipeline operators and saltwater pipeline facilities in the same manner as they apply to utilities and utility facilities.

Added by Acts 2013, 83rd Leg., R.S., Ch. 1408 (S.B. 514), Sec. 1, eff. June 14, 2013. Amended by: Acts 2017, 85th Leg., R.S., Ch. 968 (S.B. 2075), Sec. 1, eff. September 1, 2017.

GOVERNMENT CODE

TITLE 5. OPEN GOVERNMENT; ETHICS

SUBTITLE A. OPEN GOVERNMENT

CHAPTER 552. PUBLIC INFORMATION

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 552.001. POLICY; CONSTRUCTION. (a) Under the fundamental philosophy of the American constitutional form of representative government that adheres to the principle that government is the servant and not the master of the people, it is the policy of this state that each person is entitled, unless otherwise expressly provided by law, at all times to complete information about the affairs of government and the official acts of public officials and employees. The people, in delegating authority, do not give their public servants the right to decide what is good for the people to know and what is not good for them to know. The people insist on remaining informed so that they may retain control over the instruments they have created. The provisions of this chapter shall be liberally construed to implement this policy.

(b) This chapter shall be liberally construed in favor of granting a request for information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.002. DEFINITION OF PUBLIC INFORMATION; MEDIA CONTAINING PUBLIC INFORMATION. (a) In this chapter, "public information" means information that is written, produced, collected, assembled, or maintained under a law or ordinance or in connection with the transaction of official business:

(1) by a governmental body;

(2) for a governmental body and the governmental body:

(A) owns the information;

(B) has a right of access to the information; or

(C) spends or contributes public money for the purpose of writing, producing, collecting, assembling, or maintaining the information; or

(3) by an individual officer or employee of a governmental body in the officer's or employee's official capacity and the information pertains to official business of the governmental body.

(a-1) Information is in connection with the transaction of official business if the information is created by, transmitted to, received by, or maintained by an officer or employee of the governmental body in the officer's or employee's official capacity, or a person or entity performing official business or a governmental function on behalf of a governmental body, and pertains to official business of the governmental body.

(a-2) The definition of "public information" provided by Subsection (a) applies to and includes any electronic communication created, transmitted, received, or maintained on any device if the communication is in connection with the transaction of official business.

(b) The media on which public information is recorded include:

(1) paper;

(2) film;

(3) a magnetic, optical, solid state, or other device that can store an electronic signal;

(4) tape;

(5) Mylar; and

(6) any physical material on which information may be recorded, including linen, silk, and vellum.

(c) The general forms in which the media containing public information exist include a book, paper, letter, document, e-mail, Internet posting, text message, instant message, other electronic communication, printout, photograph, film, tape, microfiche, microfilm, photostat, sound recording, map, and drawing and a voice, data, or video representation held in computer memory.

(d) "Protected health information" as defined by Section 181.006, Health and Safety Code, is not public information and is not subject to disclosure under this chapter.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 1204 (S.B. 1368), Sec. 1, eff. September 1, 2013; Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 1, eff. September 1, 2019.

Sec. 552.003. DEFINITIONS. In this chapter:

(1) "Governmental body":

(A) means:

(i) a board, commission, department, committee, institution, agency, or office that is within or is created by the executive or legislative branch of state government and that is directed by one or more elected or appointed members;

(ii) a county commissioners court in the state;

(iii) a municipal governing body in the state;

(iv) a deliberative body that has rulemaking or quasi-judicial power and that is classified as a department, agency, or political subdivision of a county or municipality;

(v) a school district board of trustees;

(vi) a county board of school trustees;

(vii) a county board of education;

(viii) the governing board of a special district;

(ix) the governing body of a nonprofit corporation organized under Chapter 67, Water Code, that provides a water supply or wastewater service, or both, and is exempt from ad valorem taxation under Section 11.30, Tax Code;

(x) a local workforce development board created under Section 2308.253;

(xi) a nonprofit corporation that is eligible to receive funds under the federal community services block grant program and that is authorized by this state to serve a geographic area of the state;

(xii) a confinement facility operated under a contract with any division of the Texas Department of Criminal Justice;

(xiii) a civil commitment housing facility owned, leased, or operated by a vendor under contract with the state as provided by Chapter 841, Health and Safety Code;

(xiv) an entity that receives public funds in the current or preceding state fiscal year to manage the daily operations or restoration of the Alamo, or an entity that oversees such an entity; and

(xv) the part, section, or portion of an organization, corporation, commission, committee, institution, or agency that spends or that is supported in whole or in part by public funds; and

(B) does not include:

(i) the judiciary; or

(ii) an economic development entity whose mission or purpose is to develop and promote the economic growth of a state agency or political subdivision with which the entity contracts if:

(a) the entity does not receive $1 million or more in public funds from a single state agency or political subdivision in the current or preceding state fiscal year; or

(b) the entity:

(1) either:

(A) does not have the authority to make decisions or recommendations on behalf of a state agency or political subdivision regarding tax abatements or tax incentives; or

(B) does not require an officer of the state agency or political subdivision to hold office as a member of the board of directors of the entity;

(2) does not use staff or office space of the state agency or political subdivision for no or nominal consideration, unless the space is available to the public;

(3) to a reasonable degree, tracks the entity's receipt and expenditure of public funds separately from the entity's receipt and expenditure of private funds; and

(4) provides at least quarterly public reports to the state agency or political subdivision regarding work performed on behalf of the state agency or political subdivision.

(1-a) "Contracting information" means the following information maintained by a governmental body or sent between a governmental body and a vendor, contractor, potential vendor, or potential contractor:

(A) information in a voucher or contract relating to the receipt or expenditure of public funds by a governmental body;

(B) solicitation or bid documents relating to a contract with a governmental body;

(C) communications sent between a governmental body and a vendor, contractor, potential vendor, or potential contractor during the solicitation, evaluation, or negotiation of a contract;

(D) documents, including bid tabulations, showing the criteria by which a governmental body evaluates each vendor, contractor, potential vendor, or potential contractor responding to a solicitation and, if applicable, an explanation of why the vendor or contractor was selected; and

(E) communications and other information sent between a governmental body and a vendor or contractor related to the performance of a final contract with the governmental body or work performed on behalf of the governmental body.

(1-b) "Honorably retired" means, with respect to a position, an individual who:

(A) previously served but is not currently serving in the position;

(B) did not retire in lieu of any disciplinary action;

(C) was eligible to retire from the position or was ineligible to retire only as a result of an injury received in the course of the individual's employment in the position; and

(D) is eligible to receive a pension or annuity for service in the position or is ineligible to receive a pension or annuity only because the entity that employed the individual does not offer a pension or annuity to its employees.

(2) "Manipulation" means the process of modifying, reordering, or decoding of information with human intervention.

(2-a) "Official business" means any matter over which a governmental body has any authority, administrative duties, or advisory duties.

(3) "Processing" means the execution of a sequence of coded instructions by a computer producing a result.

(4) "Programming" means the process of producing a sequence of coded instructions that can be executed by a computer.

(5) "Public funds" means funds of the state or of a governmental subdivision of the state.

(6) "Requestor" means a person who submits a request to a governmental body for inspection or copies of public information.

(7) "Temporary custodian" means an officer or employee of a governmental body who, in the transaction of official business, creates or receives public information that the officer or employee has not provided to the officer for public information of the governmental body or the officer's agent. The term includes a former officer or employee of a governmental body who created or received public information in the officer's or employee's official capacity that has not been provided to the officer for public information of the governmental body or the officer's agent.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995; Acts 1999, 76th Leg., ch. 62, Sec. 18.24, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 633, Sec. 2, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1004, Sec. 2, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 1276, Sec. 9.014, eff. Sept. 1, 2003. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 1204 (S.B. 1368), Sec. 2, eff. September 1, 2013; Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 1, eff. January 1, 2020; Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 2, eff. September 1, 2019; Acts 2021, 87th Leg., R.S., Ch. 590 (S.B. 841), Sec. 1, eff. June 14, 2021;Acts 2021, 87th Leg., R.S., Ch. 915 (H.B. 3607), Sec. 21.001(35), eff. September 1, 2021.

Sec. 552.0031. BUSINESS DAYS. (a) Except as provided by this section, in this chapter "business day" means a day other than:

(1) a Saturday or Sunday;

(2) a national holiday under Section 662.003(a); or

(3) a state holiday under Section 662.003(b).

(b) The fact that an employee works from an alternative work site does not affect whether a day is considered a business day under this chapter.

(c) An optional holiday under Section 662.003(c) is not a business day of a governmental body if the officer for public information of the governmental body observes the optional holiday.

(d) A holiday established by the governing body of an institution of higher education under Section 662.011(a) is not a business day of the institution of higher education.

(e) The Friday before or Monday after a holiday described by Subsection (a)(2) or (3) is not a business day of a governmental body if the holiday occurs on a Saturday or Sunday and the governmental body observes the holiday on that Friday or Monday.

(f) Subject to the requirements of this subsection, a governmental body may designate a day on which the governmental body's administrative offices are closed or operating with minimum staffing as a nonbusiness day. The designation of a nonbusiness day for an independent school district must be made by the board of trustees. The designation of a nonbusiness day for a governmental body other than an independent school district must be made by the executive director or other chief administrative officer. A governmental body may designate not more than 10 nonbusiness days under this subsection each calendar year.

Added by Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 1, eff. September 1, 2023.

Sec. 552.0035. ACCESS TO INFORMATION OF JUDICIARY. (a) Access to information collected, assembled, or maintained by or

for the judiciary is governed by rules adopted by the Supreme Court of Texas or by other applicable laws and rules.

(b) This section does not address whether information is considered to be information collected, assembled, or maintained by or for the judiciary.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 1, eff. Sept. 1, 1999.

Sec. 552.004. PRESERVATION OF INFORMATION. (a) A governmental body or, for information of an elective county office, the elected county officer, may determine a time for which information that is not currently in use will be preserved, subject to Subsection (b) and to any applicable rule or law governing the destruction and other disposition of state and local government records or public information.

(b) A current or former officer or employee of a governmental body who maintains public information on a privately owned device shall:

(1) forward or transfer the public information to the governmental body or a governmental body server to be preserved as provided by Subsection (a); or

(2) preserve the public information in its original form in a backup or archive and on the privately owned device for the time described under Subsection (a).

(c) The provisions of Chapter 441 of this code and Title 6, Local Government Code, governing the preservation, destruction, or other disposition of records or public information apply to records and public information held by a temporary custodian.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995. Amended by: Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 3, eff. September 1, 2019.

Sec. 552.005. EFFECT OF CHAPTER ON SCOPE OF CIVIL DISCOVERY. (a) This chapter does not affect the scope of civil discovery under the Texas Rules of Civil Procedure.

(b) Exceptions from disclosure under this chapter do not create new privileges from discovery.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.0055. SUBPOENA DUCES TECUM OR DISCOVERY REQUEST. A subpoena duces tecum or a request for discovery that is issued in compliance with a statute or a rule of civil or criminal procedure is not considered to be a request for information under this chapter.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 2, eff. Sept. 1, 1999.

Sec. 552.006. EFFECT OF CHAPTER ON WITHHOLDING PUBLIC INFORMATION. This chapter does not authorize the withholding of public information or limit the availability of public information to the public, except as expressly provided by this chapter.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995.

Sec. 552.007. VOLUNTARY DISCLOSURE OF CERTAIN INFORMATION WHEN DISCLOSURE NOT REQUIRED. (a) This chapter does not prohibit a governmental body or its officer for public information from voluntarily making part or all of its information available to the public, unless the disclosure is expressly prohibited by law or the information is confidential under law.

(b) Public information made available under Subsection (a) must be made available to any person.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995.

Sec. 552.008. INFORMATION FOR LEGISLATIVE PURPOSES. (a) This chapter does not grant authority to withhold information from individual members, agencies, or committees of the legislature to use for legislative purposes.

(b) A governmental body on request by an individual member, agency, or committee of the legislature shall provide public information, including confidential information, to the requesting member, agency, or committee for inspection or duplication in accordance with this chapter if the requesting member, agency, or committee states that the public information is requested under this chapter for legislative purposes. A governmental body, by providing public information under this section that is confidential or otherwise excepted from required disclosure under law, does not waive or affect the confidentiality of the information for purposes of state or federal law or waive the right to assert exceptions to required disclosure of the information in the future. The governmental body may require the requesting individual member of the legislature, the requesting legislative agency or committee, or the members or employees of the requesting entity who will view or handle information that is received under this section and that is confidential under law to sign a confidentiality agreement that covers the information and requires that:

(1) the information not be disclosed outside the requesting entity, or within the requesting entity for purposes other than the purpose for which it was received;

(2) the information be labeled as confidential;

(3) the information be kept securely; or

(4) the number of copies made of the information or the notes taken from the information that implicate the confidential nature of the information be controlled, with all copies or notes that are not destroyed or returned to the governmental body remaining confidential and subject to the confidentiality agreement.

(b-1) A member, committee, or agency of the legislature required by a governmental body to sign a confidentiality agreement under Subsection (b) may seek a decision as provided by Subsection (b-2) about whether the information covered by the confidentiality agreement is confidential under law. A confidentiality agreement signed under Subsection (b) is void to the extent that the agreement covers information that is finally determined under Subsection (b-2) to not be confidential under law.

(b-2) The member, committee, or agency of the legislature may seek a decision from the attorney general about the matter. The attorney general by rule shall establish procedures and deadlines for receiving information necessary to decide the matter and briefs from the requestor, the governmental body, and any other interested person. The attorney general shall promptly render a decision requested under this subsection, determining whether the information covered by the confidentiality agreement is confidential under law, not later than the 45th business day after the date the attorney general received the request for a decision under this subsection. The attorney general shall issue a written decision on the matter and provide a copy of the decision to the requestor, the governmental body, and any interested person who submitted necessary information or a brief to the attorney general about the matter. The requestor or the governmental body may appeal a decision of the attorney general under this subsection to a Travis County district court. A person may appeal a decision of the attorney general under this subsection to a Travis County district court if the person claims a proprietary interest in the information affected by the decision or a privacy interest

in the information that a confidentiality law or judicial decision is designed to protect.

(c) This section does not affect:

(1) the right of an individual member, agency, or committee of the legislature to obtain information from a governmental body under other law, including under the rules of either house of the legislature;

(2) the procedures under which the information is obtained under other law; or

(3) the use that may be made of the information obtained under other law.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1364 (S.B. 671), Sec. 1, eff. September 1, 2010; Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 2, eff. September 1, 2010.

Sec. 552.009. OPEN RECORDS STEERING COMMITTEE: ADVICE TO ATTORNEY GENERAL; ELECTRONIC AVAILABILITY OF PUBLIC INFORMATION. (a) The open records steering committee is composed of two representatives of the attorney general's office and:

(1) a representative of each of the following, appointed by its governing entity:

(A) the comptroller's office;

(B) the Department of Public Safety;

(C) the Department of Information Resources; and

(D) the Texas State Library and Archives Commission;

(2) five public members, appointed by the attorney general; and

(3) a representative of each of the following types of local governments, appointed by the attorney general:

(A) a municipality;

(B) a county; and

(C) a school district.

Text of subsection as amended by Acts 2005, 79th Leg., R.S., Ch. 329 (S.B. 727), Sec. 1

(b) The representative of the attorney general designated by the attorney general is the presiding officer of the committee. The committee shall meet as prescribed by committee procedures or at the call of the presiding officer.

Text of subsection as amended by Acts 2005, 79th Leg., R.S., Ch. 716 (S.B. 452), Sec. 1

(b) The representative of the attorney general is the presiding officer of the committee. The committee shall meet as prescribed by committee procedures or at the call of the presiding officer.

(c) The committee shall advise the attorney general regarding the office of the attorney general's performance of its duties under Sections 552.010, 552.205, 552.262, 552.269, and 552.274.

(d) The members of the committee who represent state governmental bodies and the public members of the committee shall periodically study and determine the types of public information for which it would be useful to the public or cost-effective for the government if the type of information were made available by state governmental bodies by means of the Internet or another electronic format. The committee shall report its findings and recommendations to the governor, the presiding officer of each house of the legislature, and the budget committee and state affairs committee of each house of the legislature.

(e) Chapter 2110 does not apply to the size, composition, or duration of the committee. Chapter 2110 applies to the

reimbursement of a public member's expenses related to service on the committee. Any reimbursement of the expenses of a member who represents a state or local governmental body may be paid only from funds available to the state or local governmental body the member represents.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 3, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 1, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 1, eff. September 1, 2005; Acts 2007, 80th Leg., R.S., Ch. 937 (H.B. 3560), Sec. 3.06, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 3, eff. September 1, 2009.

Sec. 552.010. STATE GOVERNMENTAL BODIES: FISCAL AND OTHER INFORMATION RELATING TO MAKING INFORMATION ACCESSIBLE. (a) Each state governmental body shall report to the attorney general the information the attorney general requires regarding:

(1) the number and nature of requests for information the state governmental body processes under this chapter in the period covered by the report; and

(2) the cost to the state governmental body in that period in terms of capital expenditures and personnel time of:

(A) responding to requests for information under this chapter; and

(B) making information available to the public by means of the Internet or another electronic format.

(b) The attorney general shall design and phase in the reporting requirements in a way that:

(1) minimizes the reporting burden on state governmental bodies; and

(2) allows the legislature and state governmental bodies to estimate the extent to which it is cost-effective for state government, and if possible the extent to which it is cost-effective or useful for members of the public, to make information available to the public by means of the Internet or

another electronic format as a supplement or alternative to publicizing the information only in other ways or making the information available only in response to requests made under this chapter.

(c) The attorney general shall share the information reported under this section with the open records steering committee.

Added by Acts 2003, 78th Leg., 3rd C.S., ch. 3, Sec. 27.01, eff. Jan. 11, 2004. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 2, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 2, eff. September 1, 2005.

Sec. 552.011. UNIFORMITY. The attorney general shall maintain uniformity in the application, operation, and interpretation of this chapter. To perform this duty, the attorney general may prepare, distribute, and publish any materials, including detailed and comprehensive written decisions and opinions, that relate to or are based on this chapter.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 4, eff. Sept. 1, 1999.

Sec. 552.012. OPEN RECORDS TRAINING. (a) This section applies to an elected or appointed public official who is:

(1) a member of a multimember governmental body;

(2) the governing officer of a governmental body that is headed by a single officer rather than by a multimember governing body; or

(3) the officer for public information of a governmental body, without regard to whether the officer is elected or appointed to a specific term.

(b) Each public official shall complete a course of training of not less than one and not more than two hours regarding the responsibilities of the governmental body with

which the official serves and its officers and employees under this chapter not later than the 90th day after the date the public official:

(1) takes the oath of office, if the person is required to take an oath of office to assume the person's duties as a public official; or

(2) otherwise assumes the person's duties as a public official, if the person is not required to take an oath of office to assume the person's duties.

(b-1) The attorney general may require each public official of a governmental body to complete the course of training if the attorney general determines that the governmental body has failed to comply with a requirement of this chapter. The attorney general must notify each public official in writing of the attorney general's determination and the requirement to complete the training. A public official who receives notice from the attorney general under this subsection must complete the training not later than the 60th day after the date the official receives the notice.

(c) A public official may designate a public information coordinator to satisfy the training requirements of this section for the public official if the public information coordinator is primarily responsible for administering the responsibilities of the public official or governmental body under this chapter. Designation of a public information coordinator under this subsection does not relieve a public official from the duty to comply with any other requirement of this chapter that applies to the public official. The designated public information coordinator shall complete the training course regarding the responsibilities of the governmental body with which the coordinator serves and of its officers and employees under this chapter not later than the 90th day after the date the coordinator assumes the person's duties as coordinator.

(d) The attorney general shall ensure that the training is made available. The office of the attorney general may provide the training and may also approve any acceptable course of

training offered by a governmental body or other entity. The attorney general shall ensure that at least one course of training approved or provided by the attorney general is available on videotape or a functionally similar and widely available medium at no cost. The training must include instruction in:

(1) the general background of the legal requirements for open records and public information;

(2) the applicability of this chapter to governmental bodies;

(3) procedures and requirements regarding complying with a request for information under this chapter;

(4) the role of the attorney general under this chapter; and

(5) penalties and other consequences for failure to comply with this chapter.

(e) The office of the attorney general or other entity providing the training shall provide a certificate of course completion to persons who complete the training required by this section. A governmental body shall maintain and make available for public inspection the record of its public officials' or, if applicable, the public information coordinator's completion of the training.

(f) Completing the required training as a public official of the governmental body satisfies the requirements of this section with regard to the public official's service on a committee or subcommittee of the governmental body and the public official's ex officio service on any other governmental body.

(g) The training required by this section may be used to satisfy any corresponding training requirements concerning this chapter or open records required by law for a public official or public information coordinator. The attorney general shall attempt to coordinate the training required by this section with training required by other law to the extent practicable.

(h) A certificate of course completion is admissible as evidence in a criminal prosecution under this chapter. However, evidence that a defendant completed a course of training offered under this section is not prima facie evidence that the defendant knowingly violated this chapter.

Added by Acts 2005, 79th Leg., Ch. 105 (S.B. 286), Sec. 2, eff. January 1, 2006. Amended by: Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 2, eff. September 1, 2023.

SUBCHAPTER B. RIGHT OF ACCESS TO PUBLIC INFORMATION

Sec. 552.021. AVAILABILITY OF PUBLIC INFORMATION. Public information is available to the public at a minimum during the normal business hours of the governmental body.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 2, eff. Sept. 1, 1995.

Sec. 552.0215. RIGHT OF ACCESS TO CERTAIN INFORMATION AFTER 75 YEARS. (a) Except as provided by Section 552.147, the confidentiality provisions of this chapter, or other law, information that is not confidential but is excepted from required disclosure under Subchapter C is public information and is available to the public on or after the 75th anniversary of the date the information was originally created or received by the governmental body.

(b) This section does not limit the authority of a governmental body to establish retention periods for records under applicable law.

Added by Acts 2011, 82nd Leg., R.S., Ch. 462 (S.B. 1907), Sec. 1, eff. September 1, 2011.

Sec. 552.022. CATEGORIES OF PUBLIC INFORMATION; EXAMPLES. (a) Without limiting the amount or kind of information that is public information under this chapter, the following categories of information are public information and not excepted from required disclosure unless made confidential under this chapter or other law:

(1) a completed report, audit, evaluation, or investigation made of, for, or by a governmental body, except as provided by Section 552.108;

(2) the name, sex, ethnicity, salary, title, and dates of employment of each employee and officer of a governmental body;

(3) information in an account, voucher, or contract relating to the receipt or expenditure of public or other funds by a governmental body;

(4) the name of each official and the final record of voting on all proceedings in a governmental body;

(5) all working papers, research material, and information used to estimate the need for or expenditure of public funds or taxes by a governmental body, on completion of the estimate;

(6) the name, place of business, and the name of the municipality to which local sales and use taxes are credited, if any, for the named person, of a person reporting or paying sales and use taxes under Chapter 151, Tax Code;

(7) a description of an agency's central and field organizations, including:

(A) the established places at which the public may obtain information, submit information or requests, or obtain decisions;

(B) the employees from whom the public may obtain information, submit information or requests, or obtain decisions;

(C) in the case of a uniformed service, the members from whom the public may obtain information, submit information or requests, or obtain decisions; and

(D) the methods by which the public may obtain information, submit information or requests, or obtain decisions;

(8) a statement of the general course and method by which an agency's functions are channeled and determined, including the nature and requirements of all formal and informal policies and procedures;

(9) a rule of procedure, a description of forms available or the places at which forms may be obtained, and instructions relating to the scope and content of all papers, reports, or examinations;

(10) a substantive rule of general applicability adopted or issued by an agency as authorized by law, and a statement of general policy or interpretation of general applicability formulated and adopted by an agency;

(11) each amendment, revision, or repeal of information described by Subdivisions (7)-(10);

(12) final opinions, including concurring and dissenting opinions, and orders issued in the adjudication of cases;

(13) a policy statement or interpretation that has been adopted or issued by an agency;

(14) administrative staff manuals and instructions to staff that affect a member of the public;

(15) information regarded as open to the public under an agency's policies;

(16) information that is in a bill for attorney's fees and that is not privileged under the attorney-client privilege;

(17) information that is also contained in a public court record; and

(18) a settlement agreement to which a governmental body is a party.

(b) A court in this state may not order a governmental body or an officer for public information to withhold from public inspection any category of public information described

by Subsection (a) or to not produce the category of public information for inspection or duplication, unless the category of information is confidential under this chapter or other law.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 3, eff. Sept. 1, 1995; Acts 1999, 76th Leg., ch. 1319, Sec. 5, eff. Sept. 1, 1999. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 2, eff. September 1, 2011.

Sec. 552.0221. EMPLOYEE OR TRUSTEE OF PUBLIC EMPLOYEE PENSION SYSTEM. (a) Information concerning the employment of an employee of a public employee pension system is public information under the terms of this chapter, including information concerning the income, salary, benefits, and bonuses received from the pension system by the employee in the person's capacity as an employee of the system, and is not removed from the application of this chapter, made confidential, or otherwise excepted from the requirements of Section 552.021 by any statute intended to protect the records of persons as members, beneficiaries, or retirees of a public employee pension system in their capacity as such.

(b) Information concerning the service of a trustee of a public employee pension system is public information under the terms of this chapter, including information concerning the income, salary, benefits, and bonuses received from the pension system by the trustee in the person's capacity as a trustee of the system, and is not removed from the application of this chapter, made confidential, or otherwise excepted from the requirements of Section 552.021 by any statute intended to protect the records of persons as members, beneficiaries, or retirees of a public employee pension system in their capacity as such.

(c) Information subject to Subsections (a) and (b) must be released only to the extent the information is not excepted from required disclosure under this subchapter or Subchapter C.

(d) For purposes of this section, "benefits" does not include pension benefits provided to an individual by a pension system under the statutory plan covering the individual as a member, beneficiary, or retiree of the pension system.

Added by Acts 2009, 81st Leg., R.S., Ch. 58 (S.B. 1071), Sec. 1, eff. May 19, 2009.

Sec. 552.0222. DISCLOSURE OF CONTRACTING INFORMATION. (a) Contracting information is public and must be released unless excepted from disclosure under this chapter.

(b) The exceptions to disclosure provided by Sections 552.110 and 552.1101 do not apply to the following types of contracting information:

(1) a contract described by Section 2261.253(a), excluding any information that was properly redacted under Subsection (e) of that section;

(2) a contract described by Section 322.020(c), excluding any information that was properly redacted under Subsection (d) of that section;

(3) the following contract or offer terms or their functional equivalent:

(A) any term describing the overall or total price the governmental body will or could potentially pay, including overall or total value, maximum liability, and final price;

(B) a description of the items or services to be delivered with the total price for each if a total price is identified for the item or service in the contract;

(C) the delivery and service deadlines;

(D) the remedies for breach of contract;

(E) the identity of all parties to the contract;

(F) the identity of all subcontractors in a contract;

(G) the affiliate overall or total pricing for a vendor, contractor, potential vendor, or potential contractor;

(H) the execution dates;

(I) the effective dates; and

(J) the contract duration terms, including any extension options; or

(4) information indicating whether a vendor, contractor, potential vendor, or potential contractor performed its duties under a contract, including information regarding:

(A) a breach of contract;

(B) a contract variance or exception;

(C) a remedial action;

(D) an amendment to a contract;

(E) any assessed or paid liquidated damages;

(F) a key measures report;

(G) a progress report; and

(H) a final payment checklist.

(c) Notwithstanding Subsection (b), information described by Subdivisions (3)(A) and (B) of that subsection that relates to a retail electricity contract may not be disclosed until the delivery start date.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 2, eff. January 1, 2020.

Sec. 552.0225. RIGHT OF ACCESS TO INVESTMENT INFORMATION. (a) Under the fundamental philosophy of American government described by Section 552.001, it is the policy of this state that investments of government are investments of and for the people and the people are entitled to information regarding those investments. The provisions of this section shall be liberally construed to implement this policy.

(b) The following categories of information held by a governmental body relating to its investments are public information and not excepted from disclosure under this chapter:

(1) the name of any fund or investment entity the governmental body is or has invested in;

(2) the date that a fund or investment entity described by Subdivision (1) was established;

(3) each date the governmental body invested in a fund or investment entity described by Subdivision (1);

(4) the amount of money, expressed in dollars, the governmental body has committed to a fund or investment entity;

(5) the amount of money, expressed in dollars, the governmental body is investing or has invested in any fund or investment entity;

(6) the total amount of money, expressed in dollars, the governmental body received from any fund or investment entity in connection with an investment;

(7) the internal rate of return or other standard used by a governmental body in connection with each fund or investment entity it is or has invested in and the date on which the return or other standard was calculated;

(8) the remaining value of any fund or investment entity the governmental body is or has invested in;

(9) the total amount of fees, including expenses, charges, and other compensation, assessed against the governmental body by, or paid by the governmental body to, any fund or investment entity or principal of any fund or investment entity in which the governmental body is or has invested;

(10) the names of the principals responsible for managing any fund or investment entity in which the governmental body is or has invested;

(11) each recusal filed by a member of the governing board in connection with a deliberation or action of the governmental body relating to an investment;

(12) a description of all of the types of businesses a governmental body is or has invested in through a fund or investment entity;

(13) the minutes and audio or video recordings of each open portion of a meeting of the governmental body at which an item described by this subsection was discussed;

(14) the governmental body's percentage ownership interest in a fund or investment entity the governmental body is or has invested in;

(15) any annual ethics disclosure report submitted to the governmental body by a fund or investment entity the governmental body is or has invested in; and

(16) the cash-on-cash return realized by the governmental body for a fund or investment entity the governmental body is or has invested in.

(c) This section does not apply to the Texas Mutual Insurance Company or a successor to the company.

(d) This section does not apply to a private investment fund's investment in restricted securities, as defined in Section 552.143.

Added by Acts 2005, 79th Leg., Ch. 1338 (S.B. 121), Sec. 1, eff. June 18, 2005.

Sec. 552.023. SPECIAL RIGHT OF ACCESS TO CONFIDENTIAL INFORMATION. (a) A person or a person's authorized representative has a special right of access, beyond the right of the general public, to information held by a governmental body that relates to the person and that is protected from public disclosure by laws intended to protect that person's privacy interests.

(b) A governmental body may not deny access to information to the person, or the person's representative, to whom the information relates on the grounds that the information is considered confidential by privacy principles under this chapter but may assert as grounds for denial of access other provisions of this chapter or other law that are not intended to protect the person's privacy interests.

(c) A release of information under Subsections (a) and (b) is not an offense under Section 552.352.

(d) A person who receives information under this section may disclose the information to others only to the extent

consistent with the authorized purposes for which consent to release the information was obtained.

(e) Access to information under this section shall be provided in the manner prescribed by Sections 552.229 and 552.307.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 4, eff. Sept. 1, 1995.

Sec. 552.024. ELECTING TO DISCLOSE ADDRESS AND TELEPHONE NUMBER. (a) Except as provided by Subsection (a-1), each employee or official of a governmental body and each former employee or official of a governmental body shall choose whether to allow public access to the information in the custody of the governmental body that relates to the person's home address, home telephone number, emergency contact information, or social security number, or that reveals whether the person has family members.

(a-1) A school district may not require an employee or former employee of the district to choose whether to allow public access to the employee's or former employee's social security number.

(b) Each employee and official and each former employee and official shall state that person's choice under Subsection (a) to the main personnel officer of the governmental body in a signed writing not later than the 14th day after the date on which:

(1) the employee begins employment with the governmental body;

(2) the official is elected or appointed; or

(3) the former employee or official ends service with the governmental body.

(c) If the employee or official or former employee or official chooses not to allow public access to the information:

(1) the information is protected under Subchapter C; and

(2) the governmental body may redact the information from any information the governmental body discloses under Section 552.021 without the necessity of requesting a decision from the attorney general under Subchapter G.

(c-1) If, under Subsection (c)(2), a governmental body redacts or withholds information without requesting a decision from the attorney general about whether the information may be redacted or withheld, the requestor is entitled to seek a decision from the attorney general about the matter. The attorney general by rule shall establish procedures and deadlines for receiving information necessary to decide the matter and briefs from the requestor, the governmental body, and any other interested person. The attorney general shall promptly render a decision requested under this subsection, determining whether the redacted or withheld information was excepted from required disclosure to the requestor, not later than the 45th business day after the date the attorney general received the request for a decision under this subsection. The attorney general shall issue a written decision on the matter and provide a copy of the decision to the requestor, the governmental body, and any interested person who submitted necessary information or a brief to the attorney general about the matter. The requestor or the governmental body may appeal a decision of the attorney general under this subsection to a Travis County district court.

(c-2) A governmental body that redacts or withholds information under Subsection (c)(2) shall provide the following information to the requestor on a form prescribed by the attorney general:

(1) a description of the redacted or withheld information;

(2) a citation to this section; and

(3) instructions regarding how the requestor may seek a decision from the attorney general regarding whether the

redacted or withheld information is excepted from required disclosure.

(d) If an employee or official or a former employee or official fails to state the person's choice within the period established by this section, the information is subject to public access.

(e) An employee or official or former employee or official of a governmental body who wishes to close or open public access to the information may request in writing that the main personnel officer of the governmental body close or open access.

(f) This section does not apply to a person to whom Section 552.1175 applies.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 5, eff. Sept. 1, 1995; Acts 2001, 77th Leg., ch. 119, Sec. 1, eff. Sept. 1, 2001. Amended by: Acts 2009, 81st Leg., R.S., Ch. 283 (S.B. 1068), Sec. 1, eff. June 4, 2009; Acts 2011, 82nd Leg., R.S., Ch. 927 (S.B. 1638), Sec. 1, eff. June 17, 2011; Acts 2013, 83rd Leg., R.S., Ch. 183 (H.B. 2961), Sec. 1, eff. September 1, 2013.

Sec. 552.027. EXCEPTION: INFORMATION AVAILABLE COMMERCIALLY; RESOURCE MATERIAL. (a) A governmental body is not required under this chapter to allow the inspection of or to provide a copy of information in a commercial book or publication purchased or acquired by the governmental body for research purposes if the book or publication is commercially available to the public.

(b) Although information in a book or publication may be made available to the public as a resource material, such as a library book, a governmental body is not required to make a copy of the information in response to a request for public information.

(c) A governmental body shall allow the inspection of information in a book or publication that is made part of,

incorporated into, or referred to in a rule or policy of a governmental body.

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 12, eff. Sept. 1, 1995.

SUBCHAPTER C. INFORMATION EXCEPTED FROM REQUIRED DISCLOSURE

Sec. 552.101. EXCEPTION: CONFIDENTIAL INFORMATION. Information is excepted from the requirements of Section 552.021 if it is information considered to be confidential by law, either constitutional, statutory, or by judicial decision.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.102. EXCEPTION: CONFIDENTIALITY OF CERTAIN PERSONNEL INFORMATION. (a) Information is excepted from the requirements of Section 552.021 if it is information in a personnel file, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy, except that all information in the personnel file of an employee of a governmental body is to be made available to that employee or the employee's designated representative as public information is made available under this chapter. The exception to public disclosure created by this subsection is in addition to any exception created by Section 552.024. Public access to personnel information covered by Section 552.024 is denied to the extent provided by that section.

(b) Information is excepted from the requirements of Section 552.021 if it is a transcript from an institution of higher education maintained in the personnel file of a professional public school employee, except that this section does not exempt from disclosure the degree obtained or the

curriculum on a transcript in the personnel file of the employee.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 6, eff. Sept. 1, 1995. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 3, eff. September 1, 2011.

Sec. 552.103. EXCEPTION: LITIGATION OR SETTLEMENT NEGOTIATIONS INVOLVING THE STATE OR A POLITICAL SUBDIVISION. (a) Information is excepted from the requirements of Section 552.021 if it is information relating to litigation of a civil or criminal nature to which the state or a political subdivision is or may be a party or to which an officer or employee of the state or a political subdivision, as a consequence of the person's office or employment, is or may be a party.

(b) For purposes of this section, the state or a political subdivision is considered to be a party to litigation of a criminal nature until the applicable statute of limitations has expired or until the defendant has exhausted all appellate and postconviction remedies in state and federal court.

(c) Information relating to litigation involving a governmental body or an officer or employee of a governmental body is excepted from disclosure under Subsection (a) only if the litigation is pending or reasonably anticipated on the date that the requestor applies to the officer for public information for access to or duplication of the information.

(d) The exception to disclosure provided by this section does not apply to information requested under this chapter if:

(1) the information relates to a general, primary, or special election, as those terms are defined by Section 1.005, Election Code;

(2) the information is in the possession of a governmental body that administers elections described by Subdivision (1); and

(3) the governmental body described by Subdivision (2) is not a governmental body described by Section 552.003(1)(A)(i).

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 6, eff. Sept. 1, 1999. Amended by: Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 3, eff. September 1, 2023.

Sec. 552.105. EXCEPTION: INFORMATION RELATED TO LOCATION OR PRICE OF PROPERTY. Information is excepted from the requirements of Section 552.021 if it is information relating to:

(1) the location of real or personal property for a public purpose prior to public announcement of the project; or

(2) appraisals or purchase price of real or personal property for a public purpose prior to the formal award of contracts for the property.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.106. EXCEPTION: CERTAIN LEGISLATIVE DOCUMENTS. (a) A draft or working paper involved in the preparation of proposed legislation is excepted from the requirements of Section 552.021.

(b) An internal bill analysis or working paper prepared by the governor's office for the purpose of evaluating proposed legislation is excepted from the requirements of Section 552.021.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1997, 75th Leg., ch. 1437, Sec. 1, eff. June 20, 1997.

Sec. 552.107. EXCEPTION: CERTAIN LEGAL MATTERS. Information is excepted from the requirements of Section 552.021 if:

(1) it is information that the attorney general or an attorney of a political subdivision is prohibited from disclosing because of a duty to the client under the Texas Rules of Evidence or the Texas Disciplinary Rules of Professional Conduct; or

(2) a court by order has prohibited disclosure of the information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 7, eff. Sept. 1, 1995. Amended by: Acts 2005, 79th Leg., Ch. 728 (H.B. 2018), Sec. 8.014, eff. September 1, 2005.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 1620 and H.B. 1610, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.108. EXCEPTION: CERTAIN LAW ENFORCEMENT, CORRECTIONS, AND PROSECUTORIAL INFORMATION. (a) Information held by a law enforcement agency or prosecutor that deals with the detection, investigation, or prosecution of crime is excepted from the requirements of Section 552.021 if:

(1) release of the information would interfere with the detection, investigation, or prosecution of crime;

(2) it is information that deals with the detection, investigation, or prosecution of crime only in relation to an investigation that did not result in conviction or deferred adjudication;

(3) it is information relating to a threat against a peace officer or detention officer collected or disseminated under Section 411.048; or

(4) it is information that:

(A) is prepared by an attorney representing the state in anticipation of or in the course of preparing for criminal litigation; or

(B) reflects the mental impressions or legal reasoning of an attorney representing the state.

(b) An internal record or notation of a law enforcement agency or prosecutor that is maintained for internal use in matters relating to law enforcement or prosecution is excepted from the requirements of Section 552.021 if:

(1) release of the internal record or notation would interfere with law enforcement or prosecution;

(2) the internal record or notation relates to law enforcement only in relation to an investigation that did not result in conviction or deferred adjudication; or

(3) the internal record or notation:

(A) is prepared by an attorney representing the state in anticipation of or in the course of preparing for criminal litigation; or

(B) reflects the mental impressions or legal reasoning of an attorney representing the state.

(c) This section does not except from the requirements of Section 552.021 information that is basic information about an arrested person, an arrest, or a crime. A governmental body shall promptly release basic information responsive to a request made under this chapter unless the governmental body seeks to withhold the information as provided by another provision of this chapter, and regardless of whether the governmental body requests an attorney general decision under Subchapter G regarding other information subject to the request.

Text of subsection as added by Acts 2023, 88th Leg., R.S., Ch. 986 (H.B. 30), Sec. 1

(d) The exception to disclosure provided by Subsection (a)(2) does not apply to information, records, or notations if:

(1) a person who is described by or depicted in the information, record, or notation, other than a peace officer, is deceased or incapacitated; or

(2) each person who is described by or depicted in the information, record, or notation, other than a person who is deceased or incapacitated, consents to the release of the information, record, or notation.

Text of subsection as added by Acts 2023, 88th Leg., R.S., Ch. 195 (S.B. 435), Sec. 1

(d) Notwithstanding other law, a prosecutor may permit a person to view the following evidence of a crime that resulted in the death of a person and that occurred in the prosecutor's jurisdiction:

(1) a medical examiner's report, if the person viewing the report is a family member of the person who is the subject of the report and the person who is the subject of the report was a victim of the crime; and

(2) video evidence of the crime, if the person viewing the video is a victim of the crime or a family member of a victim of the crime.

(e) A person permitted to view a medical examiner's report or video evidence under Subsection (d) may not duplicate, record, capture, or otherwise memorialize the information. A prosecutor may require a person to sign a confidentiality agreement before permitting the person to view the information.

(f) A permitted viewing of a medical examiner's report or video evidence under Subsection (d) is not a voluntary disclosure of information for purposes of Section 552.007(b). A governmental body, by providing information under Subsection (d) that is confidential or otherwise excepted from required disclosure under law, does not waive or affect the confidentiality of the information for purposes of state or

federal law or waive the right to assert exceptions to required disclosure of the information in the future.

(g) Subsection (d) does not affect:

(1) the right of a person to obtain a medical examiner's report or video evidence of a crime from a governmental body under other law;

(2) the procedures under which the information is obtained under other law; or

(3) the use that may be made of the information obtained under other law.

(h) In this section:

(1) "Family member" means a person related to a victim of a crime within the first degree of consanguinity or affinity.

(2) "Medical examiner's report" means a report and the contents of such a report created by a medical examiner under Article 49.25, Code of Criminal Procedure, including an autopsy report and toxicology report. The term does not include a photograph or medical image contained in a report.

(3) "Victim" means an individual who suffered personal injury or death as a result of criminal conduct.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 7, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 1, eff. Sept. 1, 1997; Acts 2001, 77th Leg., ch. 474, Sec. 6, eff. Sept. 1, 2001. Amended by: Acts 2005, 79th Leg., Ch. 557 (H.B. 1262), Sec. 3, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 557 (H.B. 1262), Sec. 4, eff. September 1, 2005; Acts 2023, 88th Leg., R.S., Ch. 195 (S.B. 435), Sec. 1, eff. May 24, 2023; Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 4, eff. September 1, 2023; Acts 2023, 88th Leg., R.S., Ch. 986 (H.B. 30), Sec. 1, eff. September 1, 2023.

Sec. 552.109. EXCEPTION: CONFIDENTIALITY OF CERTAIN PRIVATE COMMUNICATIONS OF AN ELECTED OFFICE HOLDER. Private

correspondence or communications of an elected office holder relating to matters the disclosure of which would constitute an invasion of privacy are excepted from the requirements of Section 552.021.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 4, eff. September 1, 2011.

Sec. 552.110. EXCEPTION: CONFIDENTIALITY OF TRADE SECRETS; CONFIDENTIALITY OF CERTAIN COMMERCIAL OR FINANCIAL INFORMATION. (a) In this section, "trade secret" means all forms and types of information, including business, scientific, technical, economic, or engineering information, and any formula, design, prototype, pattern, plan, compilation, program device, program, code, device, method, technique, process, procedure, financial data, or list of actual or potential customers or suppliers, whether tangible or intangible and whether or however stored, compiled, or memorialized physically, electronically, graphically, photographically, or in writing if:

(1) the owner of the trade secret has taken reasonable measures under the circumstances to keep the information secret; and

(2) the information derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable through proper means by, another person who can obtain economic value from the disclosure or use of the information.

(b) Except as provided by Section 552.0222, information is excepted from the requirements of Section 552.021 if it is demonstrated based on specific factual evidence that the information is a trade secret.

(c) Except as provided by Section 552.0222, commercial or financial information for which it is demonstrated based on specific factual evidence that disclosure would cause substantial competitive harm to the person from whom the

information was obtained is excepted from the requirements of Section 552.021.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 7, eff. Sept. 1, 1999. Amended by: Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 4, eff. January 1, 2020.

Sec. 552.1101. EXCEPTION: CONFIDENTIALITY OF PROPRIETARY INFORMATION. (a) Except as provided by Section 552.0222, information submitted to a governmental body by a vendor, contractor, potential vendor, or potential contractor in response to a request for a bid, proposal, or qualification is excepted from the requirements of Section 552.021 if the vendor, contractor, potential vendor, or potential contractor that the information relates to demonstrates based on specific factual evidence that disclosure of the information would:

(1) reveal an individual approach to:

(A) work;

(B) organizational structure;

(C) staffing;

(D) internal operations;

(E) processes; or

(F) discounts, pricing methodology, pricing per kilowatt hour, cost data, or other pricing information that will be used in future solicitation or bid documents; and

(2) give advantage to a competitor.

(b) The exception to disclosure provided by Subsection (a) does not apply to:

(1) information in a voucher or contract relating to the receipt or expenditure of public funds by a governmental body; or

(2) communications and other information sent between a governmental body and a vendor or contractor related to the performance of a final contract with the governmental body or work performed on behalf of the governmental body.

(c) The exception to disclosure provided by Subsection (a) may be asserted only by a vendor, contractor, potential vendor, or potential contractor in the manner described by Section 552.305(b) for the purpose of protecting the interests of the vendor, contractor, potential vendor, or potential contractor. A governmental body shall decline to release information as provided by Section 552.305(a) to the extent necessary to allow a vendor, contractor, potential vendor, or potential contractor to assert the exception to disclosure provided by Subsection (a).

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 5, eff. January 1, 2020.

Sec. 552.111. EXCEPTION: AGENCY MEMORANDA. An interagency or intraagency memorandum or letter that would not be available by law to a party in litigation with the agency is excepted from the requirements of Section 552.021.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.112. EXCEPTION: CERTAIN INFORMATION RELATING TO REGULATION OF FINANCIAL INSTITUTIONS OR SECURITIES. (a) Information is excepted from the requirements of Section 552.021 if it is information contained in or relating to examination, operating, or condition reports prepared by or for an agency responsible for the regulation or supervision of financial institutions or securities, or both.

(b) In this section, "securities" has the meaning assigned by The Securities Act (Title 12, Government Code).

(c) Information is excepted from the requirements of Section 552.021 if it is information submitted by an individual or other entity to the Texas Legislative Council, or to any state agency or department overseen by the Finance Commission of Texas and the information has been or will be sent to the Texas

Legislative Council, for the purpose of performing a statistical or demographic analysis of information subject to Section 323.020. However, this subsection does not except from the requirements of Section 552.021 information that does not identify or tend to identify an individual or other entity and that is subject to required public disclosure under Section 323.020(e).

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 2003, 78th Leg., ch. 918, Sec. 2, eff. June 20, 2003. Amended by: Acts 2019, 86th Leg., R.S., Ch. 491 (H.B. 4171), Sec. 2.19, eff. January 1, 2022.

Sec. 552.113. EXCEPTION: CONFIDENTIALITY OF GEOLOGICAL OR GEOPHYSICAL INFORMATION. (a) Information is excepted from the requirements of Section 552.021 if it is:

(1) an electric log confidential under Subchapter M, Chapter 91, Natural Resources Code;

(2) geological or geophysical information or data, including maps concerning wells, except information filed in connection with an application or proceeding before an agency; or

(3) confidential under Subsections (c) through (f).

(b) Information that is shown to or examined by an employee of the General Land Office, but not retained in the land office, is not considered to be filed with the land office.

(c) In this section:

(1) "Confidential material" includes all well logs, geological, geophysical, geochemical, and other similar data, including maps and other interpretations of the material filed in the General Land Office:

(A) in connection with any administrative application or proceeding before the land commissioner, the school land board, any board for lease, or the commissioner's or board's staff; or

(B) in compliance with the requirements of any law, rule, lease, or agreement.

(2) "Electric logs" has the same meaning as it has in Chapter 91, Natural Resources Code.

(3) "Administrative applications" and "administrative proceedings" include applications for pooling or unitization, review of shut-in royalty payments, review of leases or other agreements to determine their validity, review of any plan of operations, review of the obligation to drill offset wells, or an application to pay compensatory royalty.

(d) Confidential material, except electric logs, filed in the General Land Office on or after September 1, 1985, is public information and is available to the public under Section 552.021 on and after the later of:

(1) five years from the filing date of the confidential material; or

(2) one year from the expiration, termination, or forfeiture of the lease in connection with which the confidential material was filed.

(e) Electric logs filed in the General Land Office on or after September 1, 1985, are either public information or confidential material to the same extent and for the same periods provided for the same logs by Chapter 91, Natural Resources Code. A person may request that an electric log that has been filed in the General Land Office be made confidential by filing with the land office a copy of the written request for confidentiality made to the Railroad Commission of Texas for the same log.

(f) The following are public information:

(1) electric logs filed in the General Land Office before September 1, 1985; and

(2) confidential material, except electric logs, filed in the General Land Office before September 1, 1985, provided, that Subsection (d) governs the disclosure of that confidential material filed in connection with a lease that is a valid and subsisting lease on September 1, 1995.

(g) Confidential material may be disclosed at any time if the person filing the material, or the person's successor in interest in the lease in connection with which the confidential material was filed, consents in writing to its release. A party consenting to the disclosure of confidential material may restrict the manner of disclosure and the person or persons to whom the disclosure may be made.

(h) Notwithstanding the confidential nature of the material described in this section, the material may be used by the General Land Office in the enforcement, by administrative proceeding or litigation, of the laws governing the sale and lease of public lands and minerals, the regulations of the land office, the school land board, or of any board for lease, or the terms of any lease, pooling or unitization agreement, or any other agreement or grant.

(i) An administrative hearings officer may order that confidential material introduced in an administrative proceeding remain confidential until the proceeding is finally concluded, or for the period provided in Subsection (d), whichever is later.

(j) Confidential material examined by an administrative hearings officer during the course of an administrative proceeding for the purpose of determining its admissibility as evidence shall not be considered to have been filed in the General Land Office to the extent that the confidential material is not introduced into evidence at the proceeding.

(k) This section does not prevent a person from asserting that any confidential material is exempt from disclosure as a trade secret or commercial information under Section 552.110 or under any other basis permitted by law.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 8, eff. Sept. 1, 1995. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 6, eff. September 1, 2011; Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 4, eff. September 1, 2013;

Acts 2013, 83rd Leg., R.S., Ch. 279 (H.B. 878), Sec. 5, eff. September 1, 2013.

Sec. 552.116. EXCEPTION: AUDIT WORKING PAPERS. (a) An audit working paper of an audit of the state auditor or the auditor of a state agency, an institution of higher education as defined by Section 61.003, Education Code, a county, a municipality, a school district, a hospital district, or a joint board operating under Section 22.074, Transportation Code, including any audit relating to the criminal history background check of a public school employee, is excepted from the requirements of Section 552.021. If information in an audit working paper is also maintained in another record, that other record is not excepted from the requirements of Section 552.021 by this section.

(b) In this section:

(1) "Audit" means an audit authorized or required by a statute of this state or the United States, the charter or an ordinance of a municipality, an order of the commissioners court of a county, the bylaws adopted by or other action of the governing board of a hospital district, a resolution or other action of a board of trustees of a school district, including an audit by the district relating to the criminal history background check of a public school employee, or a resolution or other action of a joint board described by Subsection (a) and includes an investigation.

(2) "Audit working paper" includes all information, documentary or otherwise, prepared or maintained in conducting an audit or preparing an audit report, including:

(A) intra-agency and interagency communications; and

(B) drafts of the audit report or portions of those drafts.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1997, 75th Leg., ch. 1122, Sec. 10, eff.

Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 8, eff. Sept. 1, 1999; Acts 2003, 78th Leg., ch. 379, Sec. 1, eff. June 18, 2003. Amended by: Acts 2005, 79th Leg., Ch. 202 (H.B. 1285), Sec. 1, eff. May 27, 2005. Acts 2005, 79th Leg., Ch. 202 (H.B. 1285), Sec. 2, eff. May 27, 2005; Acts 2007, 80th Leg., R.S., Ch. 1372 (S.B. 9), Sec. 24, eff. June 15, 2007; Acts 2007, 80th Leg., R.S., Ch. 1372 (S.B. 9), Sec. 25, eff. June 15, 2007; Acts 2011, 82nd Leg., R.S., Ch. 1170 (H.B. 2947), Sec. 1, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 1170 (H.B. 2947), Sec. 2, eff. June 17, 2011.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 2878, S.B. 370 and S.B. 1569, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.117. EXCEPTION: CONFIDENTIALITY OF CERTAIN ADDRESSES, TELEPHONE NUMBERS, SOCIAL SECURITY NUMBERS, AND PERSONAL FAMILY INFORMATION. (a) Information is excepted from the requirements of Section 552.021 if it is information that relates to the home address, home telephone number, emergency contact information, or social security number of the following person or that reveals whether the person has family members:

(1) a current or former official or employee of a governmental body, except as otherwise provided by Section 552.024;

(2) a current or honorably retired peace officer as defined by Article 2A.001, Code of Criminal Procedure, or a current or honorably retired security officer commissioned under Section 51.212, Education Code, regardless of whether the officer complies with Section 552.024 or 552.1175, as applicable;

(3) a current or former employee of the Texas Department of Criminal Justice or of the predecessor in function of the department or any division of the department, regardless

of whether the current or former employee complies with Section 552.1175;

(4) a peace officer as defined by Article 2A.001, Code of Criminal Procedure, or other law, a reserve law enforcement officer, a commissioned deputy game warden, or a corrections officer in a municipal, county, or state penal institution in this state who was killed in the line of duty, regardless of whether the deceased complied with Section 552.024 or 552.1175;

(5) a commissioned security officer as defined by Section 1702.002, Occupations Code, regardless of whether the officer complies with Section 552.024 or 552.1175, as applicable;

(6) an officer or employee of a community supervision and corrections department established under Chapter 76 who performs a duty described by Section 76.004(b), regardless of whether the officer or employee complies with Section 552.024 or 552.1175;

(7) a current or former employee of the office of the attorney general who is or was assigned to a division of that office the duties of which involve law enforcement or are performed under Chapter 231, Family Code, regardless of whether the current or former employee complies with Section 552.024 or 552.1175;

(8) a current or former employee of the Texas Juvenile Justice Department or of the predecessors in function of the department, regardless of whether the current or former employee complies with Section 552.024 or 552.1175;

(9) a current or former juvenile probation or supervision officer certified by the Texas Juvenile Justice Department, or the predecessors in function of the department, under Title 12, Human Resources Code, regardless of whether the current or former officer complies with Section 552.024 or 552.1175;

(10) a current or former employee of a juvenile justice program or facility, as those terms are defined by

Section 261.405, Family Code, regardless of whether the current or former employee complies with Section 552.024 or 552.1175;

(11) a current or former member of the United States Army, Navy, Air Force, Coast Guard, or Marine Corps, an auxiliary service of one of those branches of the armed forces, or the Texas military forces, as that term is defined by Section 437.001;

(12) a current or former district attorney, criminal district attorney, or county or municipal attorney whose jurisdiction includes any criminal law or child protective services matters, regardless of whether the current or former attorney complies with Section 552.024 or 552.1175;

(13) a current or former employee of a district attorney, criminal district attorney, or county or municipal attorney whose jurisdiction includes any criminal law or child protective services matters, regardless of whether the current or former employee complies with Section 552.024 or 552.1175;

(14) a current or former employee of the Texas Civil Commitment Office or of the predecessor in function of the office or a division of the office, regardless of whether the current or former employee complies with Section 552.024 or 552.1175;

(15) a current or former federal judge or state judge, as those terms are defined by Section 1.005, Election Code, a federal bankruptcy judge, a marshal of the United States Marshals Service, a United States attorney, or a family member of a current or former federal judge, including a federal bankruptcy judge, a marshal of the United States Marshals Service, a United States attorney, or a state judge;

(16) a current or former child protective services caseworker, adult protective services caseworker, or investigator for the Department of Family and Protective Services, regardless of whether the caseworker or investigator complies with Section 552.024 or 552.1175, or a current or former employee of a department contractor performing child protective services caseworker, adult protective services

caseworker, or investigator functions for the contractor on behalf of the department;

(17) an elected public officer, regardless of whether the officer complies with Section 552.024 or 552.1175;

(18) a current or former United States attorney, assistant United States attorney, federal public defender, deputy federal public defender, or assistant federal public defender and the spouse or child of the current or former attorney or public defender, regardless of whether the person complies with Section 552.024 or 552.1175; or

(19) a firefighter or volunteer firefighter or emergency medical services personnel as defined by Section 773.003, Health and Safety Code, regardless of whether the firefighter or volunteer firefighter or emergency medical services personnel comply with Section 552.024 or 552.1175, as applicable.

(b) All documents filed with a county clerk and all documents filed with a district clerk are exempt from this section.

(c) In this section, "family member" has the meaning assigned by Section 31.006, Finance Code.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 9, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 512, Sec. 1, eff. May 31, 1997; Acts 1999, 76th Leg., ch. 1318, Sec. 1, eff. June 18, 1999; Acts 2001, 77th Leg., ch. 119, Sec. 2, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 947, Sec. 1, eff. June 20, 2003. Amended by: Acts 2007, 80th Leg., R.S., Ch. 621 (H.B. 455), Sec. 1, eff. September 1, 2007; Acts 2011, 82nd Leg., R.S., Ch. 927 (S.B. 1638), Sec. 2, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 953 (H.B. 1046), Sec. 1, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 9, eff. September 1, 2011; Acts 2013, 83rd Leg., R.S., Ch. 1033 (H.B. 2733), Sec. 2, eff. September 1, 2013; Acts 2015, 84th Leg., R.S., Ch. 170 (H.B. 2152), Sec. 2, eff. September 1, 2015;

Acts 2015, 84th Leg., R.S., Ch. 527 (H.B. 1311), Sec. 1, eff. June 16, 2015; Acts 2017, 85th Leg., R.S., Ch. 34 (S.B. 1576), Sec. 12, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 190 (S.B. 42), Sec. 17, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 1006 (H.B. 1278), Sec. 1, eff. June 15, 2017; Acts 2019, 86th Leg., R.S., Ch. 367 (H.B. 1351), Sec. 2, eff. September 1, 2019; Acts 2019, 86th Leg., R.S., Ch. 633 (S.B. 1494), Sec. 1, eff. June 10, 2019; Acts 2019, 86th Leg., R.S., Ch. 1146 (H.B. 2910), Sec. 7, eff. September 1, 2019; Acts 2019, 86th Leg., R.S., Ch. 1213 (S.B. 662), Sec. 1, eff. June 14, 2019; Acts 2019, 86th Leg., R.S., Ch. 1245 (H.B. 2446), Sec. 4, eff. June 14, 2019; Acts 2021, 87th Leg., R.S., Ch. 65 (H.B. 1082), Sec. 1, eff. May 19, 2021; Acts 2021, 87th Leg., R.S., Ch. 383 (S.B. 1134), Sec. 8, eff. September 1, 2021; Acts 2021, 87th Leg., R.S., Ch. 383 (S.B. 1134), Sec. 9, eff. September 1, 2021; Acts 2021, 87th Leg., R.S., Ch. 507 (S.B. 56), Sec. 1, eff. June 14, 2021; Acts 2021, 87th Leg., R.S., Ch. 590 (S.B. 841), Sec. 2, eff. June 14, 2021; Acts 2021, 87th Leg., R.S., Ch. 915 (H.B. 3607), Sec. 9.010, eff. September 1, 2021; Acts 2023, 88th Leg., R.S., Ch. 152 (S.B. 870), Sec. 21, eff. September 1, 2023; Acts 2023, 88th Leg., R.S., Ch. 765 (H.B. 4504), Sec. 2.097, eff. January 1, 2025.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see S.B. 370, S.B. 2878, S.B. 1540 and S.B. 1569, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.1175. EXCEPTION: CONFIDENTIALITY OF CERTAIN PERSONAL IDENTIFYING INFORMATION OF PEACE OFFICERS AND OTHER OFFICIALS PERFORMING SENSITIVE GOVERNMENTAL FUNCTIONS. (a) This section applies only to:

(1) current or honorably retired peace officers as defined by Article 2A.001, Code of Criminal Procedure, or special investigators as described by Article 2A.002, Code of Criminal Procedure;

(2) current or honorably retired county jailers as defined by Section 1701.001, Occupations Code;

(3) current or former employees of the Texas Department of Criminal Justice or of the predecessor in function of the department or any division of the department;

(4) commissioned security officers as defined by Section 1702.002, Occupations Code;

(5) a current or former district attorney, criminal district attorney, or county or municipal attorney whose jurisdiction includes any criminal law or child protective services matters;

(5-a) a current or former employee of a district attorney, criminal district attorney, or county or municipal attorney whose jurisdiction includes any criminal law or child protective services matters;

(6) officers and employees of a community supervision and corrections department established under Chapter 76 who perform a duty described by Section 76.004(b);

(7) criminal investigators of the United States as described by Article 2A.002(a), Code of Criminal Procedure;

(8) current or honorably retired police officers and inspectors of the United States Federal Protective Service;

(9) current and former employees of the office of the attorney general who are or were assigned to a division of that office the duties of which involve law enforcement or are performed under Chapter 231, Family Code;

(10) current or former juvenile probation and detention officers certified by the Texas Juvenile Justice Department, or the predecessors in function of the department, under Title 12, Human Resources Code;

(11) current or former employees of a juvenile justice program or facility, as those terms are defined by Section 261.405, Family Code;

(12) current or former employees of the Texas Juvenile Justice Department or the predecessors in function of the department;

(13) federal judges and state judges as defined by Section 1.005, Election Code;

(14) current or former employees of the Texas Civil Commitment Office or of the predecessor in function of the office or a division of the office;

(15) a current or former member of the United States Army, Navy, Air Force, Coast Guard, or Marine Corps, an auxiliary service of one of those branches of the armed forces, or the Texas military forces, as that term is defined by Section 437.001;

(16) a current or former child protective services caseworker, adult protective services caseworker, or investigator for the Department of Family and Protective Services or a current or former employee of a department contractor performing child protective services caseworker, adult protective services caseworker, or investigator functions for the contractor on behalf of the department;

(17) an elected public officer;

(18) a firefighter or volunteer firefighter or emergency medical services personnel as defined by Section 773.003, Health and Safety Code; and

(19) a current or former United States attorney, assistant United States attorney, federal public defender, deputy federal public defender, or assistant federal public defender.

(b) Information that relates to the home address, home telephone number, emergency contact information, date of birth, or social security number of an individual to whom this section applies, or that reveals whether the individual has family members is confidential and may not be disclosed to the public under this chapter if the individual to whom the information relates:

(1) chooses to restrict public access to the information; and

(2) notifies the governmental body of the individual's choice on a form provided by the governmental body, accompanied by evidence of the individual's status.

(c) A choice made under Subsection (b) remains valid until rescinded in writing by the individual.

(d) This section does not apply to information in the tax appraisal records of an appraisal district to which Section 25.025, Tax Code, applies.

(e) All documents filed with a county clerk and all documents filed with a district clerk are exempt from this section.

(f) A governmental body may redact information that must be withheld under Subsection (b) from any information the governmental body discloses under Section 552.021 without the necessity of requesting a decision from the attorney general under Subchapter G.

(g) If, under Subsection (f), a governmental body redacts or withholds information without requesting a decision from the attorney general about whether the information may be redacted or withheld, the requestor is entitled to seek a decision from the attorney general about the matter. The attorney general by rule shall establish procedures and deadlines for receiving information necessary to decide the matter and briefs from the requestor, the governmental body, and any other interested person. The attorney general shall promptly render a decision requested under this subsection, determining whether the redacted or withheld information was excepted from required disclosure to the requestor, not later than the 45th business day after the date the attorney general received the request for a decision under this subsection. The attorney general shall issue a written decision on the matter and provide a copy of the decision to the requestor, the governmental body, and any interested person who submitted necessary information or a brief to the attorney general about the matter. The requestor or the governmental body may appeal a decision of the attorney general under this subsection to a Travis County district court.

(h) A governmental body that redacts or withholds information under Subsection (f) shall provide the following information to the requestor on a form prescribed by the attorney general:

(1) a description of the redacted or withheld information;

(2) a citation to this section; and

(3) instructions regarding how the requestor may seek a decision from the attorney general regarding whether the redacted or withheld information is excepted from required disclosure.

Added by Acts 2001, 77th Leg., ch. 119, Sec. 3, eff. Sept. 1, 2001. Amended by Acts 2003, 78th Leg., ch. 947, Sec. 2, eff. June 20, 2003. Amended by: Acts 2005, 79th Leg., Ch. 715 (S.B. 450), Sec. 1, eff. June 17, 2005; Acts 2005, 79th Leg., Ch. 715 (S.B. 450), Sec. 2, eff. June 17, 2005; Acts 2007, 80th Leg., R.S., Ch. 621 (H.B. 455), Sec. 2, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 283 (S.B. 1068), Sec. 2, eff. June 4, 2009; Acts 2009, 81st Leg., R.S., Ch. 732 (S.B. 390), Sec. 2, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 927 (S.B. 1638), Sec. 3, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 953 (H.B. 1046), Sec. 2, eff. June 17, 2011; Acts 2013, 83rd Leg., R.S., Ch. 937 (H.B. 1632), Sec. 2, eff. June 14, 2013; Acts 2013, 83rd Leg., R.S., Ch. 937 (H.B. 1632), Sec. 3, eff. June 14, 2013; Acts 2013, 83rd Leg., R.S., Ch. 1033 (H.B. 2733), Sec. 3, eff. September 1, 2013; Acts 2013, 83rd Leg., R.S., Ch. 1033 (H.B. 2733), Sec. 4, eff. September 1, 2013; Acts 2015, 84th Leg., R.S., Ch. 527 (H.B. 1311), Sec. 2, eff. June 16, 2015; Acts 2015, 84th Leg., R.S., Ch. 1236 (S.B. 1296), Sec. 9.008, eff. September 1, 2015; Acts 2017, 85th Leg., R.S., Ch. 34 (S.B. 1576), Sec. 14, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 1006 (H.B. 1278), Sec. 2, eff. June 15, 2017; Acts 2019, 86th Leg., R.S., Ch. 367 (H.B. 1351), Sec. 3, eff. September 1, 2019; Acts 2019, 86th Leg., R.S., Ch. 367 (H.B. 1351), Sec. 4, eff. September 1, 2019; Acts 2019, 86th

Leg., R.S., Ch. 633 (S.B. 1494), Sec. 2, eff. June 10, 2019; Acts 2019, 86th Leg., R.S., Ch. 633 (S.B. 1494), Sec. 3, eff. June 10, 2019; Acts 2019, 86th Leg., R.S., Ch. 1146 (H.B. 2910), Sec. 8, eff. September 1, 2019; Acts 2019, 86th Leg., R.S., Ch. 1213 (S.B. 662), Sec. 2, eff. June 14, 2019; Acts 2019, 86th Leg., R.S., Ch. 1213 (S.B. 662), Sec. 3, eff. June 14, 2019; Acts 2019, 86th Leg., R.S., Ch. 1245 (H.B. 2446), Sec. 5, eff. June 14, 2019; Acts 2019, 86th Leg., R.S., Ch. 1245 (H.B. 2446), Sec. 6, eff. June 14, 2019; Acts 2021, 87th Leg., R.S., Ch. 65 (H.B. 1082), Sec. 2, eff. May 19, 2021; Acts 2021, 87th Leg., R.S., Ch. 507 (S.B. 56), Sec. 2, eff. June 14, 2021; Acts 2021, 87th Leg., R.S., Ch. 590 (S.B. 841), Sec. 3, eff. June 14, 2021; Acts 2021, 87th Leg., R.S., Ch. 915 (H.B. 3607), Sec. 9.011, eff. September 1, 2021; Acts 2023, 88th Leg., R.S., Ch. 152 (S.B. 870), Sec. 22, eff. September 1, 2023; Acts 2023, 88th Leg., R.S., Ch. 765 (H.B. 4504), Sec. 2.098, eff. January 1, 2025.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 5093, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.11765. CONFIDENTIALITY OF CERTAIN INFORMATION MAINTAINED BY STATE LICENSING AUTHORITY. (a) In this section, "license" means a license, certificate, registration, permit, or other authorization that:

(1) is issued by a governmental body described by Section 552.003(1)(A)(i); and

(2) an individual must obtain to practice or engage in a particular business, occupation, or profession.

(b) Except as provided by Subsections (c) and (d), information maintained by a governmental body described by Section 552.003(1)(A)(i) is confidential and excepted from the requirements of Section 552.021 if the information:

(1) is a license application; or

(2) relates to the home address, home telephone number, electronic mail address, social security number, date of birth, driver's license number, state identification number, passport number, emergency contact information, or payment information of:

(A) an applicant for a license issued by the governmental body;

(B) an individual who holds a license issued by the governmental body; or

(C) an individual who previously held a license issued by the governmental body.

(c) Subsection (b) does not make confidential or except from required public disclosure the name, license number, or license status of an applicant for a license, a license holder, or an individual who previously held a license.

(d) For a license issued under Chapter 42, 43, 103, or 161, Human Resources Code, or Chapter 142, 242, 247, 248A, 250, or 252, Health and Safety Code, Subsection (b) does not prohibit the disclosure of:

(1) the last four digits of the social security number of a license holder in connection with a verification of employability or an employee misconduct registry search provided by the Health and Human Services Commission;

(2) a home address where activity regulated by the licensing authority occurs; or

(3) an e-mail address or phone number associated with activity regulated by the licensing authority.

(e) To the extent of any conflict, this section prevails over another law that authorizes or requires the release of information maintained by a governmental body.

Added by Acts 2023, 88th Leg., R.S., Ch. 73 (S.B. 510), Sec. 2, eff. September 1, 2023.

Sec. 552.121. EXCEPTION: CONFIDENTIALITY OF CERTAIN DOCUMENTS HELD FOR HISTORICAL RESEARCH. An oral history

interview, personal paper, unpublished letter, or organizational record of a nongovernmental entity that was not created or maintained in the conduct of official business of a governmental body and that is held by a private or public archival and manuscript repository for the purpose of historical research is excepted from the requirements of Section 552.021 to the extent that the archival and manuscript repository and the donor of the interview, paper, letter, or record agree to limit disclosure of the item.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 13, eff. September 1, 2011.

Sec. 552.125. EXCEPTION: CERTAIN AUDITS. Any documents or information privileged under Chapter 1101, Health and Safety Code, are excepted from the requirements of Section 552.021.

Added by Acts 1995, 74th Leg., ch. 219, Sec. 14, eff. May 23, 1995. Renumbered from Government Code Sec. 552.124 by Acts 1997, 75th Leg., ch. 165, Sec. 31.01(45), eff. Sept. 1, 1997; Acts 1997, 75th Leg., ch. 1231, Sec. 7, eff. Sept. 1, 1997. Amended by: Acts 2017, 85th Leg., R.S., Ch. 324 (S.B. 1488), Sec. 20.002(c), eff. September 1, 2017.

Sec. 552.128. EXCEPTION: CONFIDENTIALITY OF CERTAIN INFORMATION SUBMITTED BY POTENTIAL VENDOR OR CONTRACTOR. (a) Information submitted by a potential vendor or contractor to a governmental body in connection with an application for certification as a historically underutilized or disadvantaged business under a local, state, or federal certification program is excepted from the requirements of Section 552.021, except as provided by this section.

(b) Notwithstanding Section 552.007 and except as provided by Subsection (c), the information may be disclosed only:

(1) to a state or local governmental entity in this state, and the state or local governmental entity may use the information only:

(A) for purposes related to verifying an applicant's status as a historically underutilized or disadvantaged business; or

(B) for the purpose of conducting a study of a public purchasing program established under state law for historically underutilized or disadvantaged businesses; or

(2) with the express written permission of the applicant or the applicant's agent.

(c) Information submitted by a vendor or contractor or a potential vendor or contractor to a governmental body in connection with a specific proposed contractual relationship, a specific contract, or an application to be placed on a bidders list, including information that may also have been submitted in connection with an application for certification as a historically underutilized or disadvantaged business, is subject to required disclosure, excepted from required disclosure, or confidential in accordance with other law.

Added by Acts 1997, 75th Leg., ch. 1227, Sec. 1, eff. June 30, 1997. Renumbered from Sec. 552.127 by Acts 1999, 76th Leg., ch. 62, Sec. 19.01(51), eff. Sept. 1, 1999. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 19, eff. September 1, 2011.

Sec. 552.137. CONFIDENTIALITY OF CERTAIN E-MAIL ADDRESSES. (a) Except as otherwise provided by this section, an e-mail address of a member of the public that is provided for the purpose of communicating electronically with a governmental body is confidential and not subject to disclosure under this chapter.

(b) Confidential information described by this section that relates to a member of the public may be disclosed if the member of the public affirmatively consents to its release.

(c) Subsection (a) does not apply to an e-mail address:

(1) provided to a governmental body by a person who has a contractual relationship with the governmental body or by the contractor's agent;

(2) provided to a governmental body by a vendor who seeks to contract with the governmental body or by the vendor's agent;

(3) contained in a response to a request for bids or proposals, contained in a response to similar invitations soliciting offers or information relating to a potential contract, or provided to a governmental body in the course of negotiating the terms of a contract or potential contract;

(4) provided to a governmental body on a letterhead, coversheet, printed document, or other document made available to the public; or

(5) provided to a governmental body for the purpose of providing public comment on or receiving notices related to an application for a license as defined by Section 2001.003(2) of this code, or receiving orders or decisions from a governmental body.

(d) Subsection (a) does not prevent a governmental body from disclosing an e-mail address for any reason to another governmental body or to a federal agency.

Added by Acts 2001, 77th Leg., ch. 356, Sec. 1, eff. May 26, 2001. Amended by Acts 2003, 78th Leg., ch. 1089, Sec. 1, eff. Sept. 1, 2003. Amended by: Acts 2009, 81st Leg., R.S., Ch. 962 (H.B. 3544), Sec. 7, eff. September 1, 2009.

Sec. 552.139. EXCEPTION: CONFIDENTIALITY OF GOVERNMENT INFORMATION RELATED TO SECURITY OR INFRASTRUCTURE ISSUES FOR COMPUTERS. (a) Information is excepted from the requirements of Section 552.021 if it is information that relates to computer network security, to restricted information under Section 2059.055, or to the design, operation, or defense of a computer network.

(b) The following information is confidential:

(1) a computer network vulnerability report;

(2) any other assessment of the extent to which data processing operations, a computer, a computer program, network, system, or system interface, or software of a governmental body or of a contractor of a governmental body is vulnerable to unauthorized access or harm, including an assessment of the extent to which the governmental body's or contractor's electronically stored information containing sensitive or critical information is vulnerable to alteration, damage, erasure, or inappropriate use;

(3) a photocopy or other copy of an identification badge issued to an official or employee of a governmental body; and

(4) information directly arising from a governmental body's routine efforts to prevent, detect, investigate, or mitigate a computer security incident, including information contained in or derived from an information security log.

(b-1) Subsection (b)(4) does not affect the notification requirements related to a breach of system security as defined by Section 521.053, Business & Commerce Code.

(c) Notwithstanding the confidential nature of the information described in this section, the information may be disclosed to a bidder if the governmental body determines that providing the information is necessary for the bidder to provide an accurate bid. A disclosure under this subsection is not a voluntary disclosure for purposes of Section 552.007.

(d) A state agency shall redact from a contract posted on the agency's Internet website under Section 2261.253 information that is made confidential by, or excepted from required public disclosure under, this section. The redaction of information under this subsection does not exempt the information from the requirements of Section 552.021 or 552.221.

Added by Acts 2001, 77th Leg., ch. 1272, Sec. 4.03, eff. June 15, 2001. Renumbered from Government Code Sec. 552.136 by Acts 2003, 78th Leg., ch. 1275, Sec. 2(76), eff. Sept. 1, 2003. Amended by: Acts 2009, 81st Leg., R.S., Ch. 183 (H.B. 1830), Sec. 4, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 927 (S.B. 1638), Sec. 5, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 29, eff. September 1, 2011; Acts 2017, 85th Leg., R.S., Ch. 555 (S.B. 532), Sec. 1, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 683 (H.B. 8), Sec. 4, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 1042 (H.B. 1861), Sec. 1, eff. June 15, 2017; Acts 2019, 86th Leg., R.S., Ch. 467 (H.B. 4170), Sec. 8.015, eff. September 1, 2019.

Sec. 552.142. EXCEPTION: CONFIDENTIALITY OF RECORDS SUBJECT TO ORDER OF NONDISCLOSURE. (a) Information is excepted from the requirements of Section 552.021 if an order of nondisclosure of criminal history record information with respect to the information has been issued under Subchapter E-1, Chapter 411.

(b) A person who is the subject of information that is excepted from the requirements of Section 552.021 under this section may deny the occurrence of the criminal proceeding to which the information relates and the exception of the information under this section, unless the information is being used against the person in a subsequent criminal proceeding.

Added by Acts 2003, 78th Leg., ch. 1236, Sec. 5, eff. Sept. 1, 2003. Amended by: Acts 2011, 82nd Leg., R.S., Ch. 731 (H.B. 961), Sec. 9, eff. June 17, 2011; Acts 2011, 82nd Leg., R.S., Ch. 731 (H.B. 961), Sec. 10, eff. June 17, 2011; Acts 2015, 84th Leg., R.S., Ch. 1070 (H.B. 2286), Sec. 2.02, eff. September 1, 2015; Acts 2015, 84th Leg., R.S., Ch. 1279 (S.B. 1902), Sec. 26, eff. September 1, 2015; Acts 2015, 84th Leg., R.S., Ch. 1279 (S.B. 1902), Sec. 27, eff. September 1, 2015.

Sec. 552.143. CONFIDENTIALITY OF CERTAIN INVESTMENT INFORMATION. (a) All information prepared or provided by a private investment fund and held by a governmental body that is not listed in Section 552.0225(b) is confidential and excepted from the requirements of Section 552.021.

(b) Unless the information has been publicly released, pre-investment and post-investment diligence information, including reviews and analyses, prepared or maintained by a governmental body or a private investment fund is confidential and excepted from the requirements of Section 552.021, except to the extent it is subject to disclosure under Subsection (c).

(c) All information regarding a governmental body's direct purchase, holding, or disposal of restricted securities that is not listed in Section 552.0225(b)(2)-(9), (11), or (13)-(16) is confidential and excepted from the requirements of Section 552.021. This subsection does not apply to a governmental body's purchase, holding, or disposal of restricted securities for the purpose of reinvestment nor does it apply to a private investment fund's investment in restricted securities. This subsection applies to information regarding a direct purchase, holding, or disposal of restricted securities by the Texas growth fund, created under Section 70, Article XVI, Texas Constitution, that is not listed in Section 552.0225(b).

(d) For the purposes of this chapter:

(1) "Private investment fund" means an entity, other than a governmental body, that issues restricted securities to a governmental body to evidence the investment of public funds for the purpose of reinvestment.

(2) "Reinvestment" means investment in a person that makes or will make other investments.

(3) "Restricted securities" has the meaning assigned by 17 C.F.R. Section 230.144(a)(3).

(e) Repealed by Acts 2011, 82nd Leg., 1st C.S., Ch. 4, Sec. 17.05(1), eff. September 28, 2011.

(f) This section does not apply to the Texas Mutual Insurance Company or a successor to the company.

Added by Acts 2005, 79th Leg., Ch. 1338 (S.B. 121), Sec. 2, eff. June 18, 2005. Amended by: Acts 2011, 82nd Leg., 1st C.S., Ch. 4 (S.B. 1), Sec. 17.05(1), eff. September 28, 2011.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 3516, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.144. EXCEPTION: WORKING PAPERS AND ELECTRONIC COMMUNICATIONS OF ADMINISTRATIVE LAW JUDGES AT STATE OFFICE OF ADMINISTRATIVE HEARINGS. The following working papers and electronic communications of an administrative law judge at the State Office of Administrative Hearings are excepted from the requirements of Section 552.021:

(1) notes and electronic communications recording the observations, thoughts, questions, deliberations, or impressions of an administrative law judge;

(2) drafts of a proposal for decision;

(3) drafts of orders made in connection with conducting contested case hearings; and

(4) drafts of orders made in connection with conducting alternative dispute resolution procedures.

Acts 2003, 78th Leg., ch. 1215, Sec. 1, eff. Sept. 1, 2003. Renumbered from Government Code, Section 552.141 by Acts 2005, 79th Leg., Ch. 728 (H.B. 2018), Sec. 23.001(35), eff. September 1, 2005. Amended by: Acts 2007, 80th Leg., R.S., Ch. 350 (S.B. 178), Sec. 1, eff. June 15, 2007.

Sec. 552.152. EXCEPTION: CONFIDENTIALITY OF INFORMATION CONCERNING PUBLIC EMPLOYEE OR OFFICER PERSONAL SAFETY. Information in the custody of a governmental body that relates to an employee or officer of the governmental body is excepted from the requirements of Section 552.021 if, under the specific circumstances pertaining to the employee or officer, disclosure

of the information would subject the employee or officer to a substantial threat of physical harm.

Added by Acts 2009, 81st Leg., R.S., Ch. 283 (S.B. 1068), Sec. 4, eff. June 4, 2009. Redesignated from Government Code, Section 552.151 by Acts 2011, 82nd Leg., R.S., Ch. 91 (S.B. 1303), Sec. 27.001(20), eff. September 1, 2011.

Sec. 552.153. PROPRIETARY RECORDS AND TRADE SECRETS INVOLVED IN CERTAIN PARTNERSHIPS. (a) In this section, "affected jurisdiction," "comprehensive agreement," "contracting person," "interim agreement," "qualifying project," and "responsible governmental entity" have the meanings assigned those terms by Section 2267.001.

(b) Information in the custody of a responsible governmental entity that relates to a proposal for a qualifying project authorized under Chapter 2267 is excepted from the requirements of Section 552.021 if:

(1) the information consists of memoranda, staff evaluations, or other records prepared by the responsible governmental entity, its staff, outside advisors, or consultants exclusively for the evaluation and negotiation of proposals filed under Chapter 2267 for which:

(A) disclosure to the public before or after the execution of an interim or comprehensive agreement would adversely affect the financial interest or bargaining position of the responsible governmental entity; and

(B) the basis for the determination under Paragraph (A) is documented in writing by the responsible governmental entity; or

(2) the records are provided by a proposer to a responsible governmental entity or affected jurisdiction under Chapter 2267 and contain:

(A) trade secrets of the proposer;

(B) financial records of the proposer, including balance sheets and financial statements, that are not generally

available to the public through regulatory disclosure or other means; or

(C) work product related to a competitive bid or proposal submitted by the proposer that, if made public before the execution of an interim or comprehensive agreement, would provide a competing proposer an unjust advantage or adversely affect the financial interest or bargaining position of the responsible governmental entity or the proposer.

(c) Except as specifically provided by Subsection (b), this section does not authorize the withholding of information concerning:

(1) the terms of any interim or comprehensive agreement, service contract, lease, partnership, or agreement of any kind entered into by the responsible governmental entity and the contracting person or the terms of any financing arrangement that involves the use of any public money; or

(2) the performance of any person developing or operating a qualifying project under Chapter 2267.

(d) In this section, "proposer" has the meaning assigned by Section 2267.001.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1334 (S.B. 1048), Sec. 2, eff. September 1, 2011. Amended by: Acts 2013, 83rd Leg., R.S., Ch. 1153 (S.B. 211), Sec. 4, eff. June 14, 2013.

Sec. 552.156. EXCEPTION: CONFIDENTIALITY OF CONTINUITY OF OPERATIONS PLAN. (a) Except as otherwise provided by this section, the following information is excepted from disclosure under this chapter:

(1) a continuity of operations plan developed under Section 412.054, Labor Code; and

(2) all records written, produced, collected, assembled, or maintained as part of the development or review of a continuity of operations plan developed under Section 412.054, Labor Code.

(b) Forms, standards, and other instructional, informational, or planning materials adopted by the office to provide guidance or assistance to a state agency in developing a continuity of operations plan under Section 412.054, Labor Code, are public information subject to disclosure under this chapter.

(c) A governmental body may disclose or make available information that is confidential under this section to another governmental body or a federal agency.

(d) Disclosing information to another governmental body or a federal agency under this section does not waive or affect the confidentiality of that information.

Added by Acts 2015, 84th Leg., R.S., Ch. 1045 (H.B. 1832), Sec. 5, eff. June 19, 2015.

Sec. 552.163. EXCEPTION: CONFIDENTIALITY OF CERTAIN ATTORNEY GENERAL SETTLEMENT NEGOTIATIONS. (a) In this section, "attorney general settlement communication" means documentary materials or information collected, assembled, drafted, developed, used, received, or maintained by or on behalf of the attorney general with respect to an investigation or litigation conducted under Subchapter E, Chapter 17, Business & Commerce Code, and that reflects or is regarding negotiations made for the purpose of achieving a resolution of a matter without the need for continuing with litigation or trial.

(b) An attorney general settlement communication is privileged and not subject to disclosure under this chapter from the date the attorney general's investigation begins, as indicated in the attorney general's case management records, until the earlier of:

(1) the 90th day after the date settlement discussions are terminated; or

(2) the earliest of the date:

(A) the case is reported closed in the attorney general's case management records;

(B) the final judgment, assurance of voluntary compliance, or other settlement agreement is entered by the court, and the period for filing a notice of appeal has passed;

(C) the settlement documents are executed by all parties, if the documents are not filed in court;

(D) the order of dismissal or nonsuit disposing of all parties is entered by the court; or

(E) all appeals are finalized.

(c) For the purpose of this section, a settlement communication does not include a document attached to or referenced in a delivered settlement proposal that is subject to disclosure under this chapter.

Added by Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 5, eff. September 1, 2023.

SUBCHAPTER D. OFFICER FOR PUBLIC INFORMATION

Sec. 552.201. IDENTITY OF OFFICER FOR PUBLIC INFORMATION. (a) The chief administrative officer of a governmental body is the officer for public information, except as provided by Subsection (b).

(b) Each elected county officer is the officer for public information and the custodian, as defined by Section 201.003, Local Government Code, of the information created or received by that county officer's office.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 14, eff. Sept. 1, 1995.

Sec. 552.202. DEPARTMENT HEADS. Each department head is an agent of the officer for public information for the purposes of complying with this chapter.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 14, eff. Sept. 1, 1995.

Sec. 552.203. GENERAL DUTIES OF OFFICER FOR PUBLIC INFORMATION. Each officer for public information, subject to penalties provided in this chapter, shall:

(1) make public information available for public inspection and copying;

(2) carefully protect public information from deterioration, alteration, mutilation, loss, or unlawful removal;

(3) repair, renovate, or rebind public information as necessary to maintain it properly; and

(4) make reasonable efforts to obtain public information from a temporary custodian if:

(A) the information has been requested from the governmental body;

(B) the officer for public information is aware of facts sufficient to warrant a reasonable belief that the temporary custodian has possession, custody, or control of the information;

(C) the officer for public information is unable to comply with the duties imposed by this chapter without obtaining the information from the temporary custodian; and

(D) the temporary custodian has not provided the information to the officer for public information or the officer's agent.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 14, eff. Sept. 1, 1995. Amended by: Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 5, eff. September 1, 2019.

Sec. 552.204. SCOPE OF RESPONSIBILITY OF OFFICER FOR PUBLIC INFORMATION. An officer for public information is responsible for the release of public information as required by this chapter. The officer is not responsible for:

(1) the use made of the information by the requestor; or

(2) the release of information after it is removed from a record as a result of an update, a correction, or a change of status of the person to whom the information pertains.

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 14, eff. Sept. 1, 1995.

Sec. 552.205. INFORMING PUBLIC OF BASIC RIGHTS AND RESPONSIBILITIES UNDER THIS CHAPTER. (a) An officer for public information shall prominently display a sign in the form prescribed by the attorney general that contains basic information about the rights of a requestor, the responsibilities of a governmental body, and the procedures for inspecting or obtaining a copy of public information under this chapter. The officer shall display the sign at one or more places in the administrative offices of the governmental body where it is plainly visible to:

(1) members of the public who request public information in person under this chapter; and

(2) employees of the governmental body whose duties include receiving or responding to requests under this chapter.

(b) The attorney general by rule shall prescribe the content of the sign and the size, shape, and other physical characteristics of the sign. In prescribing the content of the sign, the attorney general shall include plainly written basic information about the rights of a requestor, the responsibilities of a governmental body, and the procedures for inspecting or obtaining a copy of public information under this chapter that, in the opinion of the attorney general, is most useful for requestors to know and for employees of governmental

bodies who receive or respond to requests for public information to know.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 11, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 3, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 3, eff. September 1, 2005.

SUBCHAPTER E. PROCEDURES RELATED TO ACCESS

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 4219, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.221. APPLICATION FOR PUBLIC INFORMATION; PRODUCTION OF PUBLIC INFORMATION. (a) An officer for public information of a governmental body shall promptly produce public information for inspection, duplication, or both on application by any person to the officer. In this subsection, "promptly" means as soon as possible under the circumstances, that is, within a reasonable time, without delay.

(b) An officer for public information complies with Subsection (a) by:

(1) providing the public information for inspection or duplication in the offices of the governmental body; or

(2) sending copies of the public information by first class United States mail if the person requesting the information requests that copies be provided and pays the postage and any other applicable charges that the requestor has accrued under Subchapter F.

(b-1) In addition to the methods of production described by Subsection (b), an officer for public information for a governmental body complies with Subsection (a) by referring a requestor to an exact Internet location or uniform resource locator (URL) address on a website maintained by the

governmental body and accessible to the public if the requested information is identifiable and readily available on that website. If the person requesting the information prefers a manner other than access through the URL, the governmental body must supply the information in the manner required by Subsection (b).

(b-2) If an officer for public information for a governmental body provides by e-mail an Internet location or uniform resource locator (URL) address as permitted by Subsection (b-1), the e-mail must contain a statement in a conspicuous font clearly indicating that the requestor may nonetheless access the requested information by inspection or duplication or by receipt through United States mail, as provided by Subsection (b).

(c) If the requested information is unavailable at the time of the request to examine because it is in active use or in storage, the officer for public information shall certify this fact in writing to the requestor and set a date and hour within a reasonable time when the information will be available for inspection or duplication.

(d) If an officer for public information cannot produce public information for inspection or duplication within 10 business days after the date the information is requested under Subsection (a), the officer shall certify that fact in writing to the requestor and set a date and hour within a reasonable time when the information will be available for inspection or duplication.

(e) A request is considered to have been withdrawn if the requestor fails to inspect or duplicate the public information in the offices of the governmental body on or before the 60th day after the date the information is made available or fails to pay the postage and any other applicable charges accrued under Subchapter F on or before the 60th day after the date the requestor is informed of the charges.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 2, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 12, eff. Sept. 1, 1999; Acts 2003, 78th Leg., ch. 791, Sec. 1, eff. June 20, 2003. Amended by: Acts 2015, 84th Leg., R.S., Ch. 692 (H.B. 685), Sec. 1, eff. September 1, 2015; Acts 2017, 85th Leg., R.S., Ch. 520 (S.B. 79), Sec. 1, eff. September 1, 2017; Acts 2017, 85th Leg., R.S., Ch. 894 (H.B. 3107), Sec. 1, eff. September 1, 2017.

Sec. 552.2211. PRODUCTION OF PUBLIC INFORMATION WHEN ADMINISTRATIVE OFFICES CLOSED. (a) Except as provided by Section 552.233, if a governmental body closes its physical offices, but requires staff to work, including remotely, then the governmental body shall make a good faith effort to continue responding to applications for public information, to the extent staff have access to public information responsive to an application, pursuant to this chapter while its administrative offices are closed.

(b) Failure to respond to requests in accordance with Subsection (a) may constitute a refusal to request an attorney general's decision as provided by Subchapter G or a refusal to supply public information or information that the attorney general has determined is public information that is not excepted from disclosure under Subchapter C as described by Section 552.321(a).

Added by Acts 2021, 87th Leg., R.S., Ch. 164 (S.B. 1225), Sec. 2, eff. September 1, 2021.

Sec. 552.222. PERMISSIBLE INQUIRY BY GOVERNMENTAL BODY TO REQUESTOR. (a) The officer for public information and the officer's agent may not make an inquiry of a requestor except to

establish proper identification or except as provided by Subsection (b), (c), or (c-1).

(b) If what information is requested is unclear to the governmental body, the governmental body may ask the requestor to clarify the request. If a large amount of information has been requested, the governmental body may discuss with the requestor how the scope of a request might be narrowed, but the governmental body may not inquire into the purpose for which information will be used.

(c) If the information requested relates to a motor vehicle record, the officer for public information or the officer's agent may require the requestor to provide additional identifying information sufficient for the officer or the officer's agent to determine whether the requestor is eligible to receive the information under Chapter 730, Transportation Code. In this subsection, "motor vehicle record" has the meaning assigned that term by Section 730.003, Transportation Code.

(c-1) If the information requested includes a photograph described by Section 552.155(a), the officer for public information or the officer's agent may require the requestor to provide additional information sufficient for the officer or the officer's agent to determine whether the requestor is eligible to receive the information under Section 552.155(b).

(d) If by the 61st day after the date a governmental body sends a written request for clarification or discussion under Subsection (b) or an officer for public information or agent sends a written request for additional information under Subsection (c) the governmental body, officer for public information, or agent, as applicable, does not receive a written response from the requestor, the underlying request for public information is considered to have been withdrawn by the requestor.

(e) A written request for clarification or discussion under Subsection (b) or a written request for additional information under Subsection (c) must include a statement as to

the consequences of the failure by the requestor to timely respond to the request for clarification, discussion, or additional information.

(f) Except as provided by Subsection (g), if the requestor's request for public information included the requestor's physical or mailing address, the request may not be considered to have been withdrawn under Subsection (d) unless the governmental body, officer for public information, or agent, as applicable, sends the request for clarification or discussion under Subsection (b) or the written request for additional information under Subsection (c) to that address by certified mail.

(g) If the requestor's request for public information was sent by electronic mail, the request may be considered to have been withdrawn under Subsection (d) if:

(1) the governmental body, officer for public information, or agent, as applicable, sends the request for clarification or discussion under Subsection (b) or the written request for additional information under Subsection (c) by electronic mail to the same electronic mail address from which the original request was sent or to another electronic mail address provided by the requestor; and

(2) the governmental body, officer for public information, or agent, as applicable, does not receive from the requestor a written response or response by electronic mail within the period described by Subsection (d).

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1187, Sec. 5, eff. Sept. 1, 1997. Amended by: Acts 2007, 80th Leg., R.S., Ch. 296 (H.B. 1497), Sec. 1, eff. September 1, 2007; Acts 2015, 84th Leg., R.S., Ch. 762 (H.B. 2134), Sec. 1, eff. September 1, 2015; Acts 2015, 84th Leg., R.S., Ch. 835 (S.B. 46), Sec. 2, eff. September 1, 2015.

Sec. 552.223. UNIFORM TREATMENT OF REQUESTS FOR INFORMATION. The officer for public information or the officer's agent shall treat all requests for information uniformly without regard to the position or occupation of the requestor, the person on whose behalf the request is made, or the status of the individual as a member of the media.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995.

Sec. 552.224. COMFORT AND FACILITY. The officer for public information or the officer's agent shall give to a requestor all reasonable comfort and facility for the full exercise of the right granted by this chapter.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995.

Sec. 552.225. TIME FOR EXAMINATION. (a) A requestor must complete the examination of the information not later than the 10th business day after the date the custodian of the information makes it available. If the requestor does not complete the examination of the information within 10 business days after the date the custodian of the information makes the information available and does not file a request for additional time under Subsection (b), the requestor is considered to have withdrawn the request.

(b) The officer for public information shall extend the initial examination period by an additional 10 business days if, within the initial period, the requestor files with the officer for public information a written request for additional time. The officer for public information shall extend an additional examination period by another 10 business days if, within the

additional period, the requestor files with the officer for public information a written request for more additional time.

(c) The time during which a person may examine information may be interrupted by the officer for public information if the information is needed for use by the governmental body. The period of interruption is not considered to be a part of the time during which the person may examine the information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 4, eff. September 1, 2005.

Sec. 552.226. REMOVAL OF ORIGINAL RECORD. This chapter does not authorize a requestor to remove an original copy of a public record from the office of a governmental body.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995.

Sec. 552.227. RESEARCH OF STATE LIBRARY HOLDINGS NOT REQUIRED. An officer for public information or the officer's agent is not required to perform general research within the reference and research archives and holdings of state libraries.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995.

Sec. 552.228. PROVIDING SUITABLE COPY OF PUBLIC INFORMATION WITHIN REASONABLE TIME. (a) It shall be a policy of a governmental body to provide a suitable copy of public information within a reasonable time after the date on which the copy is requested.

(b) If public information exists in an electronic or magnetic medium, the requestor may request a copy in an electronic medium, such as on diskette or on magnetic tape. A governmental body shall provide a copy in the requested medium if:

(1) the governmental body has the technological ability to produce a copy of the requested information in the requested medium;

(2) the governmental body is not required to purchase any software or hardware to accommodate the request; and

(3) provision of a copy of the information in the requested medium will not violate the terms of any copyright agreement between the governmental body and a third party.

(c) If a governmental body is unable to comply with a request to produce a copy of information in a requested medium for any of the reasons described by this section, the governmental body shall provide a copy in another medium that is acceptable to the requestor. A governmental body is not required to copy information onto a diskette or other material provided by the requestor but may use its own supplies.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995. Amended by: Acts 2009, 81st Leg., R.S., Ch. 962 (H.B. 3544), Sec. 8, eff. September 1, 2009.

Sec. 552.229. CONSENT TO RELEASE INFORMATION UNDER SPECIAL RIGHT OF ACCESS. (a) Consent for the release of information excepted from disclosure to the general public but available to a specific person under Sections 552.023 and 552.307 must be in writing and signed by the specific person or the person's authorized representative.

(b) An individual under 18 years of age may consent to the release of information under this section only with the additional written authorization of the individual's parent or guardian.

(c) An individual who has been adjudicated incompetent to manage the individual's personal affairs or for whom an attorney ad litem has been appointed may consent to the release of information under this section only by the written authorization of the designated legal guardian or attorney ad litem.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.230. RULES OF PROCEDURE FOR INSPECTION AND COPYING OF PUBLIC INFORMATION. (a) A governmental body may promulgate reasonable rules of procedure under which public information may be inspected and copied efficiently, safely, and without delay.

(b) A rule promulgated under Subsection (a) may not be inconsistent with any provision of this chapter.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 3, eff. Sept. 1, 1997.

Sec. 552.231. RESPONDING TO REQUESTS FOR INFORMATION THAT REQUIRE PROGRAMMING OR MANIPULATION OF DATA. (a) A governmental body shall provide to a requestor the written statement described by Subsection (b) if the governmental body determines:

(1) that responding to a request for public information will require programming or manipulation of data; and

(2) that:

(A) compliance with the request is not feasible or will result in substantial interference with its ongoing operations; or

(B) the information could be made available in the requested form only at a cost that covers the programming and manipulation of data.

(b) The written statement must include:

(1) a statement that the information is not available in the requested form;

(2) a description of the form in which the information is available;

(3) a description of any contract or services that would be required to provide the information in the requested form;

(4) a statement of the estimated cost of providing the information in the requested form, as determined in accordance with the rules established by the attorney general under Section 552.262; and

(5) a statement of the anticipated time required to provide the information in the requested form.

(c) The governmental body shall provide the written statement to the requestor within 20 days after the date of the governmental body's receipt of the request. The governmental body has an additional 10 days to provide the statement if the governmental body gives written notice to the requestor, within 20 days after the date of receipt of the request, that the additional time is needed.

(d) On providing the written statement to the requestor as required by this section, the governmental body does not have any further obligation to provide the information in the requested form or in the form in which it is available unless within 30 days the requestor states in writing to the governmental body that the requestor:

(1) wants the governmental body to provide the information in the requested form according to the cost and time parameters set out in the statement or according to other terms to which the requestor and the governmental body agree; or

(2) wants the information in the form in which it is available.

(d-1) If a requestor does not make a timely written statement under Subsection (d), the requestor is considered to have withdrawn the request for information.

(e) The officer for public information of a governmental body shall establish policies that assure the expeditious and accurate processing of requests for information that require programming or manipulation of data. A governmental body shall maintain a file containing all written statements issued under this section in a readily accessible location.

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 15, eff. Sept. 1, 1995. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 5, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 4, eff. September 1, 2005.

Sec. 552.232. RESPONDING TO REPETITIOUS OR REDUNDANT REQUESTS. (a) A governmental body that determines that a requestor has made a request for information for which the governmental body has previously furnished copies to the requestor or made copies available to the requestor on payment of applicable charges under Subchapter F, shall respond to the request, in relation to the information for which copies have been already furnished or made available, in accordance with this section, except that:

(1) this section does not prohibit the governmental body from furnishing the information or making the information available to the requestor again in accordance with the request; and

(2) the governmental body is not required to comply with this section in relation to information that the governmental body simply furnishes or makes available to the requestor again in accordance with the request.

(b) The governmental body shall certify to the requestor that copies of all or part of the requested information, as applicable, were previously furnished to the requestor or made

available to the requestor on payment of applicable charges under Subchapter F. The certification must include:

(1) a description of the information for which copies have been previously furnished or made available to the requestor;

(2) the date that the governmental body received the requestor's original request for that information;

(3) the date that the governmental body previously furnished copies of or made available copies of the information to the requestor;

(4) a certification that no subsequent additions, deletions, or corrections have been made to that information; and

(5) the name, title, and signature of the officer for public information or the officer's agent making the certification.

(c) A charge may not be imposed for making and furnishing a certification required under Subsection (b).

(d) This section does not apply to information for which the governmental body has not previously furnished copies to the requestor or made copies available to the requestor on payment of applicable charges under Subchapter F. A request by the requestor for information for which copies have not previously been furnished or made available to the requestor, including information for which copies were not furnished or made available because the information was redacted from other information that was furnished or made available or because the information did not yet exist at the time of an earlier request, shall be treated in the same manner as any other request for information under this chapter.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 13, eff. Sept. 1, 1999.

Sec. 552.2325. TEMPORARY SUSPENSION OF REQUIREMENTS FOR GOVERNMENTAL BODY IMPACTED BY CATASTROPHE. (a) In this section:

(1) "Catastrophe" means a condition or occurrence that directly interferes with the ability of a governmental body to comply with the requirements of this chapter, including:

(A) fire, flood, earthquake, hurricane, tornado, or wind, rain, or snow storm;

(B) power failure, transportation failure, or interruption of communication facilities;

(C) epidemic; or

(D) riot, civil disturbance, enemy attack, or other actual or threatened act of lawlessness or violence.

(2) "Catastrophe" does not mean a period when staff is required to work remotely and can access information responsive to an application for information electronically, but the physical office of the governmental body is closed.

(3) "Suspension period" means the period of time during which a governmental body may suspend the applicability of the requirements of this chapter to the governmental body under this section.

(b) The requirements of this chapter do not apply to a governmental body during the suspension period determined by the governmental body under Subsections (d) and (e) if the governmental body:

(1) is currently significantly impacted by a catastrophe such that the catastrophe directly causes the inability of a governmental body to comply with the requirements of this chapter; and

(2) complies with the requirements of this section.

(c) A governmental body that elects to suspend the applicability of the requirements of this chapter to the governmental body must submit notice to the office of the attorney general that the governmental body is currently impacted by a catastrophe and has elected to suspend the applicability of those requirements during the initial

suspension period determined under Subsection (d). The notice must be on the form prescribed by the office of the attorney general under Subsection (j).

(d) A governmental body may suspend the applicability of the requirements of this chapter to the governmental body for an initial suspension period. The governmental body may suspend the applicability of the requirements of this chapter under this subsection only once for each catastrophe. The initial suspension period may not exceed seven consecutive days and must occur during the period that:

(1) begins not earlier than the second day before the date the governmental body submits notice to the office of the attorney general under Subsection (c); and

(2) ends not later than the seventh day after the date the governmental body submits that notice.

(e) A governmental body may extend an initial suspension period if the governing body determines that the governing body is still impacted by the catastrophe on which the initial suspension period was based. The initial suspension period may be extended one time for not more than seven consecutive days that begin on the day following the day the initial suspension period ends. The governing body must submit notice of the extension to the office of the attorney general on the form prescribed by the office under Subsection (l).

(f) A governmental body that initiates a suspension period under Subsection (d) may not initiate another suspension period related to the same catastrophe, except for a single extension period as prescribed in Subsection (e).

(g) The combined suspension period for a governmental body filing under Subsections (d) and (e) may not exceed a total of 14 consecutive calendar days with respect to any single catastrophe.

(h) A governmental body that suspends the applicability of the requirements of this chapter to the governmental body under this section must provide notice to the public of the suspension in a place readily accessible to the public and in each other

location the governmental body is required to post a notice under Subchapter C, Chapter 551. The governmental body must maintain the notice of the suspension during the suspension period.

(i) Notwithstanding another provision of this chapter, a request for public information received by a governmental body during a suspension period determined by the governmental body is considered to have been received by the governmental body on the first business day after the date the suspension period ends.

(j) The requirements of this chapter related to a request for public information received by a governmental body before the date an initial suspension period determined by the governmental body begins are tolled until the first business day after the date the suspension period ends.

(k) The office of the attorney general shall continuously post on the Internet website of the office each notice submitted to the office under this section from the date the office receives the notice until the first anniversary of that date.

(l) The office of the attorney general shall prescribe the form of the notice that a governmental body must submit to the office under Subsections (c) and (e). The notice must require the governmental body to:

(1) identify and describe the catastrophe that the governmental body is currently impacted by;

(2) state the date the initial suspension period determined by the governmental body under Subsection (d) begins and the date that period ends;

(3) if the governmental body has determined to extend the initial suspension period under Subsection (e):

(A) state that the governmental body continues to be impacted by the catastrophe identified in Subdivision (1); and

(B) state the date the extension to the initial suspension period begins and the date the period ends; and

(4) provide any other information the office of the attorney general determines necessary.

(m) Upon conclusion of any suspension period initiated pursuant to Subsections (d) or (e), the governmental body shall immediately resume compliance with all requirements of this chapter.

Added by Acts 2019, 86th Leg., R.S., Ch. 462 (S.B. 494), Sec. 4, eff. September 1, 2019. Amended by: Acts 2021, 87th Leg., R.S., Ch. 164 (S.B. 1225), Sec. 1, eff. September 1, 2021; Redesignated by Acts 2021, 87th Leg., R.S., Ch. 915 (H.B. 3607), Sec. 21.001(38), eff. September 1, 2021.

Sec. 552.233. OWNERSHIP OF PUBLIC INFORMATION. (a) A current or former officer or employee of a governmental body does not have, by virtue of the officer's or employee's position or former position, a personal or property right to public information the officer or employee created or received while acting in an official capacity.

(b) A temporary custodian with possession, custody, or control of public information shall surrender or return the information to the governmental body not later than the 10th day after the date the officer for public information of the governmental body or the officer's agent requests the temporary custodian to surrender or return the information.

(c) A temporary custodian's failure to surrender or return public information as required by Subsection (b) is grounds for disciplinary action by the governmental body that employs the temporary custodian or any other applicable penalties provided by this chapter or other law.

(d) For purposes of the application of Subchapter G to information surrendered or returned to a governmental body by a temporary custodian under Subsection (b), the governmental body is considered to receive the request for that information on the date the information is surrendered or returned to the governmental body.

Added by Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 6, eff. September 1, 2019.

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 4214, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.234. METHOD OF MAKING WRITTEN REQUEST FOR PUBLIC INFORMATION. (a) A person may make a written request for public information under this chapter only by delivering the request by one of the following methods to the applicable officer for public information or a person designated by that officer:

(1) United States mail;

(2) electronic mail;

(3) hand delivery; or

(4) any other appropriate method approved by the governmental body, including:

(A) facsimile transmission; and

(B) electronic submission through the governmental body's Internet website.

(b) For the purpose of Subsection (a)(4), a governmental body is considered to have approved a method described by that subdivision only if the governmental body includes a statement that a request for public information may be made by that method on:

(1) the sign required to be displayed by the governmental body under Section 552.205; or

(2) the governmental body's Internet website.

(c) A governmental body may designate one mailing address and one electronic mail address for receiving written requests for public information. The governmental body shall provide the designated mailing address and electronic mailing address to any person on request.

(d) A governmental body that posts the mailing address and electronic mail address designated by the governmental body under Subsection (c) on the governmental body's Internet website or that prints those addresses on the sign required to be displayed by the governmental body under Section 552.205 is not required to respond to a written request for public information unless the request is received:

(1) at one of those addresses;

(2) by hand delivery; or

(3) by a method described by Subsection (a)(4) that has been approved by the governmental body.

Added by Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 6, eff. September 1, 2019.

Sec. 552.235. PUBLIC INFORMATION REQUEST FORM. (a) The attorney general shall create a public information request form that provides a requestor the option of excluding from a request information that the governmental body determines is:

(1) confidential; or

(2) subject to an exception to disclosure that the governmental body would assert if the information were subject to the request.

(b) A governmental body that allows requestors to use the form described by Subsection (a) and maintains an Internet website shall post the form on its website.

Added by Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 6, eff. September 1, 2019.

SUBCHAPTER F. CHARGES FOR PROVIDING COPIES OF PUBLIC INFORMATION

Sec. 552.261. CHARGE FOR PROVIDING COPIES OF PUBLIC INFORMATION. (a) The charge for providing a copy of public information shall be an amount that reasonably includes all costs related to reproducing the public information, including

costs of materials, labor, and overhead. If a request is for 50 or fewer pages of paper records, the charge for providing the copy of the public information may not include costs of materials, labor, or overhead, but shall be limited to the charge for each page of the paper record that is photocopied, unless the pages to be photocopied are located in:

(1) two or more separate buildings that are not physically connected with each other; or

(2) a remote storage facility.

(b) If the charge for providing a copy of public information includes costs of labor, the requestor may require the governmental body's officer for public information or the officer's agent to provide the requestor with a written statement as to the amount of time that was required to produce and provide the copy. The statement must be signed by the officer for public information or the officer's agent and the officer's or the agent's name must be typed or legibly printed below the signature. A charge may not be imposed for providing the written statement to the requestor.

(c) For purposes of Subsection (a), a connection of two buildings by a covered or open sidewalk, an elevated or underground passageway, or a similar facility is insufficient to cause the buildings to be considered separate buildings.

(d) Charges for providing a copy of public information are considered to accrue at the time the governmental body advises the requestor that the copy is available on payment of the applicable charges.

(e) Except as otherwise provided by this subsection, all requests received in one calendar day from an individual may be treated as a single request for purposes of calculating costs under this chapter. A governmental body may not combine multiple requests under this subsection from separate individuals who submit requests on behalf of an organization.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 16, eff.

Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 14, eff. Sept. 1, 1999; Acts 2003, 78th Leg., ch. 864, Sec. 1, eff. Sept. 1, 2003. Amended by: Acts 2017, 85th Leg., R.S., Ch. 894 (H.B. 3107), Sec. 2, eff. September 1, 2017.

Sec. 552.2615. REQUIRED ITEMIZED ESTIMATE OF CHARGES. (a) If a request for a copy of public information will result in the imposition of a charge under this subchapter that exceeds $40, or a request to inspect a paper record will result in the imposition of a charge under Section 552.271 that exceeds $40, the governmental body shall provide the requestor with a written itemized statement that details all estimated charges that will be imposed, including any allowable charges for labor or personnel costs. If an alternative less costly method of viewing the records is available, the statement must include a notice that the requestor may contact the governmental body regarding the alternative method. The governmental body must inform the requestor of the responsibilities imposed on the requestor by this section and of the rights granted by this entire section and give the requestor the information needed to respond, including:

(1) that the requestor must provide the governmental body with a mailing, facsimile transmission, or electronic mail address to receive the itemized statement and that it is the requestor's choice which type of address to provide;

(2) that the request is considered automatically withdrawn if the requestor does not respond in writing to the itemized statement and any updated itemized statement in the time and manner required by this section; and

(3) that the requestor may respond to the statement by delivering the written response to the governmental body by mail, in person, by facsimile transmission if the governmental body is capable of receiving documents transmitted in that

manner, or by electronic mail if the governmental body has an electronic mail address.

(b) A request described by Subsection (a) is considered to have been withdrawn by the requestor if the requestor does not respond in writing to the itemized statement by informing the governmental body within 10 business days after the date the statement is sent to the requestor that:

(1) the requestor will accept the estimated charges;

(2) the requestor is modifying the request in response to the itemized statement; or

(3) the requestor has sent to the attorney general a complaint alleging that the requestor has been overcharged for being provided with a copy of the public information.

(c) If the governmental body later determines, but before it makes the copy or the paper record available, that the estimated charges will exceed the charges detailed in the written itemized statement by 20 percent or more, the governmental body shall send to the requestor a written updated itemized statement that details all estimated charges that will be imposed, including any allowable charges for labor or personnel costs. If the requestor does not respond in writing to the updated estimate in the time and manner described by Subsection (b), the request is considered to have been withdrawn by the requestor.

(d) If the actual charges that a governmental body imposes for a copy of public information, or for inspecting a paper record under Section 552.271, exceeds $40, the charges may not exceed:

(1) the amount estimated in the updated itemized statement; or

(2) if an updated itemized statement is not sent to the requestor, an amount that exceeds by 20 percent or more the amount estimated in the itemized statement.

(e) An itemized statement or updated itemized statement is considered to have been sent by the governmental body to the requestor on the date that:

(1) the statement is delivered to the requestor in person;

(2) the governmental body deposits the properly addressed statement in the United States mail; or

(3) the governmental body transmits the properly addressed statement by electronic mail or facsimile transmission, if the requestor agrees to receive the statement by electronic mail or facsimile transmission, as applicable.

(f) A requestor is considered to have responded to the itemized statement or the updated itemized statement on the date that:

(1) the response is delivered to the governmental body in person;

(2) the requestor deposits the properly addressed response in the United States mail; or

(3) the requestor transmits the properly addressed response to the governmental body by electronic mail or facsimile transmission.

(g) The time deadlines imposed by this section do not affect the application of a time deadline imposed on a governmental body under Subchapter G.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 15, eff. Sept. 1, 1999. Amended by Acts 2003, 78th Leg., ch. 864, Sec. 2, eff. Sept. 1, 2003. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 6, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 5, eff. September 1, 2005.

Sec. 552.262. RULES OF THE ATTORNEY GENERAL. (a) The attorney general shall adopt rules for use by each governmental body in determining charges for providing copies of public information under this subchapter and in determining the charge, deposit, or bond required for making public information that exists in a paper record available for inspection as authorized by Sections 552.271(c) and (d). The rules adopted by the attorney general shall be used by each governmental body in

determining charges for providing copies of public information and in determining the charge, deposit, or bond required for making public information that exists in a paper record available for inspection, except to the extent that other law provides for charges for specific kinds of public information. The charges for providing copies of public information may not be excessive and may not exceed the actual cost of producing the information or for making public information that exists in a paper record available for inspection. A governmental body, other than an agency of state government, may determine its own charges for providing copies of public information and its own charge, deposit, or bond for making public information that exists in a paper record available for inspection but may not charge an amount that is greater than 25 percent more than the amount established by the attorney general unless the governmental body requests an exemption under Subsection (c).

(b) The rules of the attorney general shall prescribe the methods for computing the charges for providing copies of public information in paper, electronic, and other kinds of media and the charge, deposit, or bond required for making public information that exists in a paper record available for inspection. The rules shall establish costs for various components of charges for providing copies of public information that shall be used by each governmental body in providing copies of public information or making public information that exists in a paper record available for inspection.

(c) A governmental body may request that it be exempt from part or all of the rules adopted by the attorney general for determining charges for providing copies of public information or the charge, deposit, or bond required for making public information that exists in a paper record available for inspection. The request must be made in writing to the attorney general and must state the reason for the exemption. If the attorney general determines that good cause exists for exempting a governmental body from a part or all of the rules, the attorney general shall give written notice of the determination

to the governmental body within 90 days of the request. On receipt of the determination, the governmental body may amend its charges for providing copies of public information or its charge, deposit, or bond required for making public information that exists in a paper record available for inspection according to the determination of the attorney general.

(d) The attorney general shall publish annually in the Texas Register a list of the governmental bodies that have authorization from the attorney general to adopt any modified rules for determining the cost of providing copies of public information or making public information that exists in a paper record available for inspection.

(e) The rules of the attorney general do not apply to a state governmental body that is not a state agency for purposes of Subtitle D, Title 10.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 16, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 7, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 6, eff. September 1, 2005.

Sec. 552.263. BOND FOR PAYMENT OF COSTS OR CASH PREPAYMENT FOR PREPARATION OF COPY OF PUBLIC INFORMATION. (a) An officer for public information or the officer's agent may require a deposit or bond for payment of anticipated costs for the preparation of a copy of public information if:

(1) the officer for public information or the officer's agent has provided the requestor with the written itemized statement required under Section 552.2615 detailing the estimated charge for providing the copy; and

(2) the charge for providing the copy of the public information specifically requested by the requestor is estimated by the governmental body to exceed:

(A) $100, if the governmental body has more than 15 full-time employees; or

(B) $50, if the governmental body has fewer than 16 full-time employees.

(b) The officer for public information or the officer's agent may not require a deposit or bond be paid under Subsection (a) as a down payment for copies of public information that the requestor may request in the future.

(c) An officer for public information or the officer's agent may require a deposit or bond for payment of unpaid amounts owing to the governmental body in relation to previous requests that the requestor has made under this chapter before preparing a copy of public information in response to a new request if those unpaid amounts exceed $100. The officer for public information or the officer's agent may not seek payment of those unpaid amounts through any other means.

(d) The governmental body must fully document the existence and amount of those unpaid amounts or the amount of any anticipated costs, as applicable, before requiring a deposit or bond under this section. The documentation is subject to required public disclosure under this chapter.

(e) For purposes of Subchapters F and G, a request for a copy of public information is considered to have been received by a governmental body on the date the governmental body receives the deposit or bond for payment of anticipated costs or unpaid amounts if the governmental body's officer for public information or the officer's agent requires a deposit or bond in accordance with this section.

(e-1) If a requestor modifies the request in response to the requirement of a deposit or bond authorized by this section, the modified request is considered a separate request for the purposes of this chapter and is considered received on the date the governmental body receives the written modified request.

(f) A requestor who fails to make a deposit or post a bond required under Subsection (a) before the 10th business day after the date the deposit or bond is required is considered to have

withdrawn the request for the copy of the public information that precipitated the requirement of the deposit or bond.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 17, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 315 (S.B. 623), Sec. 1, eff. September 1, 2005; Acts 2007, 80th Leg., R.S., Ch. 349 (S.B. 175), Sec. 1, eff. June 15, 2007; Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 6, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 38, eff. September 1, 2011.

Sec. 552.264. COPY OF PUBLIC INFORMATION REQUESTED BY MEMBER OF LEGISLATURE. One copy of public information that is requested from a state agency by a member, agency, or committee of the legislature under Section 552.008 shall be provided without charge.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1585, Sec. 1, eff. June 20, 1999.

Sec. 552.265. CHARGE FOR PAPER COPY PROVIDED BY DISTRICT OR COUNTY CLERK. The charge for providing a paper copy made by a district or county clerk's office shall be the charge provided by Chapter 51 of this code, Chapter 118, Local Government Code, or other applicable law.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 2001, 77th Leg., ch. 1155, Sec. 1, eff. June 15, 2001.

Sec. 552.266. CHARGE FOR COPY OF PUBLIC INFORMATION PROVIDED BY MUNICIPAL COURT CLERK. The charge for providing a copy made by a municipal court clerk shall be the charge provided by municipal ordinance.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997.

COPY OF PUBLIC INFORMATION. (a) A governmental body shall provide a copy of public information without charge or at a reduced charge if the governmental body determines that waiver or reduction of the charge is in the public interest because providing the copy of the information primarily benefits the general public.

(b) If the cost to a governmental body of processing the collection of a charge for providing a copy of public information will exceed the amount of the charge, the governmental body may waive the charge.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997.

Sec. 552.268. EFFICIENT USE OF PUBLIC RESOURCES. A governmental body shall make reasonably efficient use of supplies and other resources to avoid excessive reproduction costs.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997.

Sec. 552.269. OVERCHARGE OR OVERPAYMENT FOR COPY OF PUBLIC INFORMATION. (a) A person who believes the person has been overcharged for being provided with a copy of public information may complain to the attorney general in writing of the alleged overcharge, setting forth the reasons why the person believes the charges are excessive. The attorney general shall review the complaint and make a determination in writing as to the appropriate charge for providing the copy of the requested information. The governmental body shall respond to the attorney general to any written questions asked of the governmental body by the attorney general regarding the charges for providing the copy of the public information. The response must be made to the attorney general within 10 business days after the date the questions are received by the governmental body. If the attorney general determines that a governmental body has overcharged for providing the copy of requested public information, the governmental body shall promptly adjust its charges in accordance with the determination of the attorney general.

(b) A person who overpays for a copy of public information because a governmental body refuses or fails to follow the rules for charges adopted by the attorney general is entitled to recover three times the amount of the overcharge if the governmental body did not act in good faith in computing the costs.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 2003, 78th Leg., ch. 864, Sec. 3, eff. Sept. 1, 2003. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 8, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 7, eff. September 1, 2005.

Sec. 552.270. CHARGE FOR GOVERNMENT PUBLICATION. (a) This subchapter does not apply to a publication that is compiled and printed by or for a governmental body for public dissemination. If the cost of the publication is not determined by state law, a governmental body may determine the charge for providing the publication.

(b) This section does not prohibit a governmental body from providing a publication free of charge if state law does not require that a certain charge be made.

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997.

Sec. 552.271. INSPECTION OF PUBLIC INFORMATION IN PAPER RECORD IF COPY NOT REQUESTED. (a) If the requestor does not request a copy of public information, a charge may not be imposed for making available for inspection any public information that exists in a paper record, except as provided by this section.

(b) If a requested page contains confidential information that must be edited from the record before the information can be made available for inspection, the governmental body may charge for the cost of making a photocopy of the page from which confidential information must be edited. No charge other than the cost of the photocopy may be imposed under this subsection.

(c) Except as provided by Subsection (d), an officer for public information or the officer's agent may require a requestor to pay, or to make a deposit or post a bond for the payment of, anticipated personnel costs for making available for inspection public information that exists in paper records only if:

(1) the public information specifically requested by the requestor:

(A) is older than five years; or

(B) completely fills, or when assembled will completely fill, six or more archival boxes; and

(2) the officer for public information or the officer's agent estimates that more than five hours will be required to make the public information available for inspection.

(d) If the governmental body has fewer than 16 full-time employees, the payment, the deposit, or the bond authorized by Subsection (c) may be required only if:

(1) the public information specifically requested by the requestor:

(A) is older than three years; or

(B) completely fills, or when assembled will completely fill, three or more archival boxes; and

(2) the officer for public information or the officer's agent estimates that more than two hours will be required to make the public information available for inspection.

(e) A requestor who has exceeded a limit established by a governmental body under Section 552.275 may not inspect public information on behalf of another requestor unless the requestor who exceeded the limit has paid each statement issued by the governmental body under Section 552.275(e).

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 18, eff. Sept. 1, 1999. Amended by: Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 6, eff. September 1, 2023.

Sec. 552.272. INSPECTION OF ELECTRONIC RECORD IF COPY NOT REQUESTED. (a) In response to a request to inspect information that exists in an electronic medium and that is not available directly on-line to the requestor, a charge may not be imposed for access to the information, unless complying with the request will require programming or manipulation of data. If

programming or manipulation of data is required, the governmental body shall notify the requestor before assembling the information and provide the requestor with an estimate of charges that will be imposed to make the information available. A charge under this section must be assessed in accordance with this subchapter.

(b) If public information exists in an electronic form on a computer owned or leased by a governmental body and if the public has direct access to that computer through a computer network or other means, the electronic form of the information may be electronically copied from that computer without charge if accessing the information does not require processing, programming, or manipulation on the government-owned or government-leased computer before the information is copied.

(c) If public information exists in an electronic form on a computer owned or leased by a governmental body and if the public has direct access to that computer through a computer network or other means and the information requires processing, programming, or manipulation before it can be electronically copied, a governmental body may impose charges in accordance with this subchapter.

(d) If information is created or kept in an electronic form, a governmental body is encouraged to explore options to separate out confidential information and to make public information available to the public through electronic access through a computer network or by other means.

(e) The provisions of this section that prohibit a governmental entity from imposing a charge for access to information that exists in an electronic medium do not apply to the collection of a fee set by the supreme court after consultation with the Judicial Committee on Information Technology as authorized by Section 77.031 for the use of a computerized electronic judicial information system.

(f) A requestor who has exceeded a limit established by a governmental body under Section 552.275 may not inspect public information on behalf of another requestor unless the requestor

who exceeded the limit has paid each statement issued by the governmental body under Section 552.275(e).

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 17, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997; Acts 1997, 75th Leg., ch. 1327, Sec. 5, eff. Sept. 1, 1997. Amended by: Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 7, eff. September 1, 2023.

Sec. 552.274. REPORT BY ATTORNEY GENERAL ON COST OF COPIES. (a) The attorney general shall:

(1) biennially update a report prepared by the attorney general about the charges made by state agencies for providing copies of public information; and

(2) provide a copy of the updated report on the attorney general's open records page on the Internet not later than March 1 of each even-numbered year.

(b) Repealed by Acts 2011, 82nd Leg., R.S., Ch. 1083, Sec. 25(62), eff. June 17, 2011.

(c) In this section, "state agency" has the meaning assigned by Sections 2151.002(2)(A) and (C).

Added by Acts 1995, 74th Leg., ch. 693, Sec. 17, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 165, Sec. 17.19, eff. Sept. 1, 1997. Renumbered from Government Code Sec. 552.270 by Acts 1997, 75th Leg., ch. 165, Sec. 31.01(47), eff. Sept. 1, 1997. Renumbered from Government Code Sec. 552.270 and amended by Acts 1997, 75th Leg., ch. 1231, Sec. 4, eff. Sept. 1, 1997. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 19, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1420, Sec. 9.008(a), eff. Sept. 1, 2001. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 9, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 8, eff. September 1, 2005; Acts 2005, 79th Leg., Ch. 716 (S.B. 452), Sec. 9, eff. September 1, 2005; Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 7, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 1083

(S.B. 1179), Sec. 25(62), eff. June 17, 2011; Acts 2013, 83rd Leg., R.S., Ch. 161 (S.B. 1093), Sec. 9.014, eff. September 1, 2013.

Sec. 552.275. REQUESTS THAT REQUIRE LARGE AMOUNTS OF EMPLOYEE OR PERSONNEL TIME. (a) A governmental body may establish reasonable monthly and yearly limits on the amount of time that personnel of the governmental body are required to spend producing public information for inspection or duplication by a requestor, or providing copies of public information to a requestor, without recovering its costs attributable to that personnel time.

(a-1) For purposes of this section, all county officials who have designated the same officer for public information may calculate the amount of time that personnel are required to spend collectively for purposes of the monthly or yearly limit.

(b) A yearly time limit established under Subsection (a) may not be less than 36 hours for a requestor during the 12-month period that corresponds to the fiscal year of the governmental body. A monthly time limit established under Subsection (a) may not be less than 15 hours for a requestor for a one-month period.

(c) In determining whether a time limit established under Subsection (a) applies, any time spent complying with a request for public information submitted in the name of a minor, as defined by Section 101.003(a), Family Code, is to be included in the calculation of the cumulative amount of time spent complying with a request for public information by a parent, guardian, or other person who has control of the minor under a court order and with whom the minor resides, unless that parent, guardian, or other person establishes that another person submitted that request in the name of the minor.

(d) If a governmental body establishes a time limit under Subsection (a), each time the governmental body complies with a request for public information, the governmental body shall

provide the requestor with a written statement of the amount of personnel time spent complying with that request and the cumulative amount of time spent complying with requests for public information from that requestor during the applicable monthly or yearly period. The amount of time spent preparing the written statement may not be included in the amount of time included in the statement provided to the requestor under this subsection unless the requestor's time limit for the period has been exceeded.

(e) Subject to Subsection (e-1), if in connection with a request for public information, the cumulative amount of personnel time spent complying with requests for public information from the same requestor equals or exceeds the limit established by the governmental body under Subsection (a), the governmental body shall provide the requestor with a written estimate of the total cost, including materials, personnel time, and overhead expenses, necessary to comply with the request. The written estimate must be provided to the requestor on or before the 10th day after the date on which the public information was requested. The amount of this charge relating to the cost of locating, compiling, and producing the public information shall be established by rules prescribed by the attorney general under Sections 552.262(a) and (b).

(e-1) This subsection applies only to a request made by a requestor who has made a previous request to a governmental body that has not been withdrawn, for which the governmental body has located and compiled documents in response, and for which the governmental body has issued a statement under Subsection (e) that remains unpaid on the date the requestor submits the new request. A governmental body is not required to locate, compile, produce, or provide copies of documents or prepare a statement under Subsection (e) in response to a new request described by this subsection until the date the requestor pays each unpaid statement issued under Subsection (e) in connection with a previous request or withdraws the previous request to which the statement applies.

(f) If the governmental body determines that additional time is required to prepare the written estimate under Subsection (e) and provides the requestor with a written statement of that determination, the governmental body must provide the written statement under that subsection as soon as practicable, but on or before the 10th day after the date the governmental body provided the statement under this subsection.

(g) If a governmental body provides a requestor with a written statement under Subsection (e) or (o) and the time limits prescribed by Subsection (a) regarding the requestor have been exceeded, the governmental body is not required to produce public information for inspection or duplication or to provide copies of public information in response to the requestor's request unless on or before the 10th day after the date the governmental body provided the written statement under that subsection, the requestor submits payment of the amount stated in the written statement provided under Subsection (e) or provides identification or submits payment as required by Subsection (o), as applicable.

(h) If the requestor fails or refuses to provide identification or submit payment under Subsection (g), the requestor is considered to have withdrawn the requestor's pending request for public information.

(i) This section does not prohibit a governmental body from providing a copy of public information without charge or at a reduced rate under Section 552.267 or from waiving a charge for providing a copy of public information under that section.

(j) This section does not apply if the requestor is an individual who, for a substantial portion of the individual's livelihood or for substantial financial gain, gathers, compiles, prepares, collects, photographs, records, writes, edits, reports, investigates, processes, or publishes news or information for and is seeking the information for:

(1) dissemination by a news medium or communication service provider, including:

(A) an individual who supervises or assists in gathering, preparing, and disseminating the news or information; or

(B) an individual who is or was a journalist, scholar, or researcher employed by an institution of higher education at the time the person made the request for information; or

(2) creation or maintenance of an abstract plant as described by Section 2501.004, Insurance Code.

(k) This section does not apply if the requestor is an elected official of the United States, this state, or a political subdivision of this state.

(l) This section does not apply if the requestor is a representative of a publicly funded legal services organization that is exempt from federal income taxation under Section 501(a), Internal Revenue Code of 1986, as amended, by being listed as an exempt entity under Section 501(c)(3) of that code.

(m) In this section:

(1) "Communication service provider" has the meaning assigned by Section 22.021, Civil Practice and Remedies Code.

(2) "News medium" means a newspaper, magazine or periodical, a book publisher, a news agency, a wire service, an FCC-licensed radio or television station or a network of such stations, a cable, satellite, or other transmission system or carrier or channel, or a channel or programming service for a station, network, system, or carrier, or an audio or audiovisual production company or Internet company or provider, or the parent, subsidiary, division, or affiliate of that entity, that disseminates news or information to the public by any means, including:

(A) print;

(B) television;

(C) radio;

(D) photographic;

(E) mechanical;

(F) electronic; and

(G) other means, known or unknown, that are accessible to the public.

(n) A governmental body may request photo identification from a requestor for the sole purpose of establishing that the requestor has not:

(1) exceeded a limit established by the governmental body under Subsection (a); and

(2) concealed the requestor's identity.

(o) A request for photo identification under Subsection (n) must include a statement under Subsection (e) applicable to the requestor who has exceeded a limit established by the governmental body and a statement that describes each specific reason why Subsection (n) may apply to the requestor. The governmental body shall accept as proof of a requestor's identification physical presentment of photo identification or an image of the photo identification that is transmitted electronically or through the mail. A requestor from whom a governmental body has requested photo identification under Subsection (n) may decline to provide identification and obtain the requested information by paying the charge assessed in the statement.

Added by Acts 2007, 80th Leg., R.S., Ch. 1398 (H.B. 2564), Sec. 1, eff. June 15, 2007. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1383 (S.B. 1629), Sec. 1, eff. September 1, 2009; Acts 2017, 85th Leg., R.S., Ch. 894 (H.B. 3107), Sec. 3, eff. September 1, 2017; Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 8, eff. September 1, 2023.

SUBCHAPTER G. ATTORNEY GENERAL DECISIONS

The following section was amended by the 89th Legislature. Pending publication of the current statutes, see H.B. 4219, 89th Legislature, Regular Session, for amendments affecting the following section.

Sec. 552.301. REQUEST FOR ATTORNEY GENERAL DECISION. (a) A governmental body that receives a written request for information that it wishes to withhold from public disclosure and that it considers to be within one of the exceptions under Subchapter C must ask for a decision from the attorney general about whether the information is within that exception if there has not been a previous determination about whether the information falls within one of the exceptions.

(a-1) For the purposes of this subchapter, if a governmental body receives a written request by United States mail and cannot adequately establish the actual date on which the governmental body received the request, the written request is considered to have been received by the governmental body on the third business day after the date of the postmark on a properly addressed request.

(b) The governmental body must ask for the attorney general's decision and state the exceptions that apply within a reasonable time but not later than the 10th business day after the date of receiving the written request.

(c) Repealed by Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 7, eff. September 1, 2019.

(d) A governmental body that requests an attorney general decision under Subsection (a) must provide to the requestor within a reasonable time but not later than the 10th business day after the date of receiving the requestor's written request:

(1) a written statement that the governmental body wishes to withhold the requested information and has asked for a decision from the attorney general about whether the information is within an exception to public disclosure; and

(2) a copy of the governmental body's written communication to the attorney general asking for the decision or, if the governmental body's written communication to the attorney general discloses the requested information, a redacted copy of that written communication.

(e) A governmental body that requests an attorney general decision under Subsection (a) must within a reasonable time but

not later than the 15th business day after the date of receiving the written request:

(1) submit to the attorney general:

(A) written comments stating the reasons why the stated exceptions apply that would allow the information to be withheld;

(B) a copy of the written request for information;

(C) a signed statement as to the date on which the written request for information was received by the governmental body or evidence sufficient to establish that date; and

(D) a copy of the specific information requested, or submit representative samples of the information if a voluminous amount of information was requested; and

(2) label that copy of the specific information, or of the representative samples, to indicate which exceptions apply to which parts of the copy.

(e-1) A governmental body that submits written comments to the attorney general under Subsection (e)(1)(A) shall send a copy of those comments to the person who requested the information from the governmental body not later than the 15th business day after the date of receiving the written request. If the written comments disclose or contain the substance of the information requested, the copy of the comments provided to the person must be a redacted copy.

(f) A governmental body must release the requested information and is prohibited from asking for a decision from the attorney general about whether information requested under this chapter is within an exception under Subchapter C if:

(1) the governmental body has previously requested and received a determination from the attorney general concerning the precise information at issue in a pending request; and

(2) the attorney general or a court determined that the information is public information under this chapter that is not excepted by Subchapter C.

(g) A governmental body may ask for another decision from the attorney general concerning the precise information that was at issue in a prior decision made by the attorney general under this subchapter if:

(1) a suit challenging the prior decision was timely filed against the attorney general in accordance with this chapter concerning the precise information at issue;

(2) the attorney general determines that the requestor has voluntarily withdrawn the request for the information in writing or has abandoned the request; and

(3) the parties agree to dismiss the lawsuit.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 18, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1231, Sec. 5, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 20, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 10, eff. September 1, 2005; Acts 2007, 80th Leg., R.S., Ch. 474 (H.B. 2248), Sec. 1, eff. September 1, 2007; Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 8, eff. September 1, 2009; Acts 2011, 82nd Leg., R.S., Ch. 1229 (S.B. 602), Sec. 39, eff. September 1, 2011; Acts 2019, 86th Leg., R.S., Ch. 1340 (S.B. 944), Sec. 7, eff. September 1, 2019.

Sec. 552.302. FAILURE TO MAKE TIMELY REQUEST FOR ATTORNEY GENERAL DECISION; PRESUMPTION THAT INFORMATION IS PUBLIC. If a governmental body does not request an attorney general decision as provided by Section 552.301 and provide the requestor with the information required by Sections 552.301(d) and (e-1), the information requested in writing is presumed to be subject to required public disclosure and must be released unless there is a compelling reason to withhold the information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 21, eff. Sept. 1, 1999. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 11, eff. September 1, 2005.

Sec. 552.303. DELIVERY OF REQUESTED INFORMATION TO ATTORNEY GENERAL; DISCLOSURE OF REQUESTED INFORMATION; ATTORNEY GENERAL REQUEST FOR SUBMISSION OF ADDITIONAL INFORMATION. (a) A governmental body that requests an attorney general decision under this subchapter shall supply to the attorney general, in accordance with Section 552.301, the specific information requested. Unless the information requested is confidential by law, the governmental body may disclose the requested information to the public or to the requestor before the attorney general makes a final determination that the requested information is public or, if suit is filed under this chapter, before a final determination that the requested information is public has been made by the court with jurisdiction over the suit, except as otherwise provided by Section 552.322.

(b) The attorney general may determine whether a governmental body's submission of information to the attorney general under Section 552.301 is sufficient to render a decision.

(c) If the attorney general determines that information in addition to that required by Section 552.301 is necessary to render a decision, the attorney general shall give written notice of that fact to the governmental body and the requestor.

(d) A governmental body notified under Subsection (c) shall submit the necessary additional information to the attorney general not later than the seventh calendar day after the date the notice is received.

(e) If a governmental body does not comply with Subsection (d), the information that is the subject of a person's request to the governmental body and regarding which the governmental

body fails to comply with Subsection (d) is presumed to be subject to required public disclosure and must be released unless there exists a compelling reason to withhold the information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 19, eff. Sept. 1, 1995; Acts 1999, 76th Leg., ch. 1319, Sec. 22, eff. Sept. 1, 1999.

Sec. 552.3031. ELECTRONIC SUBMISSION OF REQUEST FOR ATTORNEY GENERAL DECISION. (a) This section does not apply to a request for an attorney general decision made under this subchapter if:

(1) the governmental body requesting the decision:

(A) has fewer than 16 full-time employees; or

(B) is located in a county with a population of less than 150,000;

(2) the amount or format of responsive information at issue in a particular request makes use of the attorney general's electronic filing system impractical or impossible; or

(3) the request is hand delivered to the office of the attorney general.

(b) A governmental body that requests an attorney general decision under this subchapter must submit the request through the attorney general's designated electronic filing system.

(c) The attorney general may adopt rules necessary to implement this section, including rules that define the amount or type of formatting of information described by Subsection (a)(2) that makes use of the electronic filing system impractical or impossible.

Added by Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 9, eff. September 1, 2023.

Sec. 552.3035. DISCLOSURE OF REQUESTED INFORMATION BY ATTORNEY GENERAL. The attorney general may not disclose to the requestor or the public any information submitted to the attorney general under Section 552.301(e)(1)(D).

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 23, eff. Sept. 1, 1999.

Sec. 552.304. SUBMISSION OF PUBLIC COMMENTS. (a) A person may submit written comments stating reasons why the information at issue in a request for an attorney general decision should or should not be released.

(b) A person who submits written comments to the attorney general under Subsection (a) shall send a copy of those comments to both the person who requested the information from the governmental body and the governmental body. If the written comments submitted to the attorney general disclose or contain the substance of the information requested from the governmental body, the copy of the comments sent to the person who requested the information must be a redacted copy.

(c) In this section, "written comments" includes a letter, a memorandum, or a brief.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 20, eff. Sept. 1, 1995. Amended by: Acts 2005, 79th Leg., Ch. 329 (S.B. 727), Sec. 12, eff. September 1, 2005.

Sec. 552.305. INFORMATION INVOLVING PRIVACY OR PROPERTY INTERESTS OF THIRD PARTY. (a) In a case in which information is requested under this chapter and a person's privacy or property interests may be involved, including a case under Section 552.101, 552.110, 552.1101, 552.114, 552.131, or 552.143, a governmental body may decline to release the information for the purpose of requesting an attorney general decision.

(b) A person whose interests may be involved under Subsection (a), or any other person, may submit in writing to the attorney general the person's reasons why the information should be withheld or released.

(c) The governmental body may, but is not required to, submit its reasons why the information should be withheld or released.

(d) If release of a person's proprietary information may be subject to exception under Section 552.101, 552.110, 552.1101, 552.113, 552.131, or 552.143, the governmental body that requests an attorney general decision under Section 552.301 shall make a good faith attempt to notify that person of the request for the attorney general decision. Notice under this subsection must:

(1) be in writing and sent within a reasonable time not later than the 10th business day after the date the governmental body receives the request for the information; and

(2) include:

(A) a copy of the written request for the information, if any, received by the governmental body; and

(B) a statement, in the form prescribed by the attorney general, that the person is entitled to submit in writing to the attorney general within a reasonable time not later than the 10th business day after the date the person receives the notice:

(i) each reason the person has as to why the information should be withheld; and

(ii) a letter, memorandum, or brief in support of that reason.

(e) A person who submits a letter, memorandum, or brief to the attorney general under Subsection (d) shall send a copy of that letter, memorandum, or brief to the person who requested the information from the governmental body. If the letter, memorandum, or brief submitted to the attorney general contains the substance of the information requested, the copy of the letter, memorandum, or brief may be a redacted copy.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 21, eff. Sept. 1, 1995; Acts 1999, 76th Leg., ch. 1319, Sec. 24, eff. Sept. 1, 1999. Amended by: Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 7, eff. January 1, 2020.

Sec. 552.306. RENDITION OF ATTORNEY GENERAL DECISION; ISSUANCE OF WRITTEN OPINION. (a) Except as provided by Section 552.011, the attorney general shall promptly render a decision requested under this subchapter, consistent with the standards of due process, determining whether the requested information is within one of the exceptions of Subchapter C. The attorney general shall render the decision not later than the 45th business day after the date the attorney general received the request for a decision. If the attorney general is unable to issue the decision within the 45-day period, the attorney general may extend the period for issuing the decision by an additional 10 business days by informing the governmental body and the requestor, during the original 45-day period, of the reason for the delay.

(b) The attorney general shall issue a written opinion of the determination and shall provide a copy of the opinion to the requestor.

(c) A governmental body shall as soon as practicable but within a reasonable period of time after the date the attorney general issues an opinion under Subsection (b) regarding information requested under this chapter:

(1) provide the requestor of the information an itemized estimate of charges for production of the information if the estimate is required by Section 552.2615;

(2) if the requested information is voluminous:

(A) take the following actions if the governmental body determines that it is able to disclose the information in a single batch:

(i) provide a written certified notice to the requestor and the attorney general that it is impractical or impossible for the governmental body to produce the information within a reasonable period of time;

(ii) include in the notice the date and hour that the governmental body will disclose the information to the requestor, which may not be later than the 15th business day after the date the governmental body provides the notice; and

(iii) produce the information at the date and time included in the notice; or

(B) take the following actions if the governmental body determines that it is unable to disclose the information in a single batch:

(i) provide a written certified notice to the requestor and the attorney general that it is impractical or impossible for the governmental body to produce the information within a reasonable period of time and in a single batch;

(ii) include in the notice the date and hour that the governmental body will disclose the first batch of information to the requestor, which may not be later than the 15th business day after the date the governmental body provides the notice;

(iii) provide a written certified notice to the requestor and the attorney general when each subsequent batch of information is disclosed to the requestor of the date and hour that the governmental body will disclose the next batch of information to the requestor, which may not be later than the 15th business day after the date the governmental body provides the notice; and

(iv) produce the requested information at each date and time included in a notice;

(3) produce the information if it is required to be produced;

(4) notify the requestor in writing that the governmental body is withholding the information as authorized by the opinion; or

(5) notify the requestor in writing that the governmental body has filed suit against the attorney general under Section 552.324 regarding the information.

(d) A governmental body is presumed to have complied with the requirements of Subsection (c) if the governmental body takes an action under that subsection regarding information that is the subject of an opinion issued by the attorney general not later than the 30th day after the date the attorney general issues the opinion.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 22, eff. Jan. 1, 1996; Acts 1999, 76th Leg., ch. 1319, Sec. 25, eff. Sept. 1, 1999. Amended by: Acts 2007, 80th Leg., R.S., Ch. 349 (S.B. 175), Sec. 2, eff. June 15, 2007; Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 10, eff. September 1, 2023.

Sec. 552.307. SPECIAL RIGHT OF ACCESS; ATTORNEY GENERAL DECISIONS. (a) If a governmental body determines that information subject to a special right of access under Section 552.023 is exempt from disclosure under an exception of Subchapter C, other than an exception intended to protect the privacy interest of the requestor or the person whom the requestor is authorized to represent, the governmental body shall, before disclosing the information, submit a written request for a decision to the attorney general under the procedures of this subchapter.

(b) If a decision is not requested under Subsection (a), the governmental body shall release the information to the person with a special right of access under Section 552.023 not later than the 10th business day after the date of receiving the request for information.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by: Acts 2007, 80th Leg., R.S., Ch. 349 (S.B. 175), Sec. 3, eff. June 15, 2007.

Sec. 552.308. TIMELINESS OF ACTION BY UNITED STATES MAIL, INTERAGENCY MAIL, OR COMMON OR CONTRACT CARRIER. (a) Except as provided by Section 552.3031, when this subchapter requires a request, notice, or other document to be submitted or otherwise given to a person within a specified period, the requirement is met in a timely fashion if the document is sent to the person by first class United States mail or common or contract carrier properly addressed with postage or handling charges prepaid and:

(1) it bears a post office cancellation mark or a receipt mark of a common or contract carrier indicating a time within that period; or

(2) the person required to submit or otherwise give the document furnishes satisfactory proof that it was deposited in the mail or with a common or contract carrier within that period.

(b) Except as provided by Section 552.3031, when this subchapter requires an agency of this state to submit or otherwise give to the attorney general within a specified period a request, notice, or other writing, the requirement is met in a timely fashion if:

(1) the request, notice, or other writing is sent to the attorney general by interagency mail; and

(2) the agency provides evidence sufficient to establish that the request, notice, or other writing was deposited in the interagency mail within that period.

Added by Acts 1995, 74th Leg., ch. 1035, Sec. 23, eff. Sept. 1, 1995. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 26, eff. Sept. 1, 1999; Acts 2003, 78th Leg., ch. 909, Sec. 1, 2, eff. June 20, 2003. Amended by: Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 11, eff. September 1, 2023.

Sec. 552.309. TIMELINESS OF ACTION BY ELECTRONIC SUBMISSION. (a) When this subchapter requires a request,

notice, or other document to be submitted or otherwise given to the attorney general within a specified period, the requirement is met in a timely fashion if the document is submitted to the attorney general through the attorney general's designated electronic filing system within that period.

(b) The attorney general may electronically transmit a notice, decision, or other document. When this subchapter requires the attorney general to deliver a notice, decision, or other document within a specified period, the requirement is met in a timely fashion if the document is electronically transmitted by the attorney general within that period.

(c) This section does not affect the right of a person or governmental body to submit information to the attorney general under Section 552.308.

Added by Acts 2011, 82nd Leg., R.S., Ch. 552 (H.B. 2866), Sec. 2, eff. June 17, 2011.

Sec. 552.310. SEARCHABLE DATABASE. (a) The office of the attorney general shall make available on the office's Internet website an easily accessible and searchable database consisting of:

(1) information identifying each request for an attorney general decision made under this subchapter; and

(2) the attorney general's opinion issued for the request.

(b) The database at a minimum must allow a person to search for a request or opinion described by Subsection (a) by:

(1) the name of the governmental body making the request; and

(2) the exception under Subchapter C that a governmental body asserts in the request applies to its request to withhold information from public disclosure.

(c) The database must allow a person to view the current status of a request described by Subsection (a)(1) and an

estimated timeline indicating the date each stage of review of the request will be started and completed.

Added by Acts 2023, 88th Leg., R.S., Ch. 847 (H.B. 3033), Sec. 12, eff. September 1, 2023.

SUBCHAPTER H. CIVIL ENFORCEMENT

Sec. 552.321. SUIT FOR WRIT OF MANDAMUS. (a) A requestor or the attorney general may file suit for a writ of mandamus compelling a governmental body to make information available for public inspection if the governmental body refuses to request an attorney general's decision as provided by Subchapter G or refuses to supply public information or information that the attorney general has determined is public information that is not excepted from disclosure under Subchapter C.

(b) A suit filed by a requestor under this section must be filed in a district court for the county in which the main offices of the governmental body are located. A suit filed by the attorney general under this section must be filed in a district court of Travis County, except that a suit against a municipality with a population of 100,000 or less must be filed in a district court for the county in which the main offices of the municipality are located.

(c) A requestor may file suit for a writ of mandamus compelling a governmental body or an entity to comply with the requirements of Subchapter J.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 24, eff. Sept. 1, 1995; Acts 1999, 76th Leg., ch. 1319, Sec. 27, eff. Sept. 1, 1999. Amended by: Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 8, eff. January 1, 2020.

Sec. 552.3215. DECLARATORY JUDGMENT OR INJUNCTIVE RELIEF. (a) In this section:

(1) "Complainant" means a person who claims to be the victim of a violation of this chapter.

(2) "State agency" means a board, commission, department, office, or other agency that:

(A) is in the executive branch of state government;

(B) was created by the constitution or a statute of this state; and

(C) has statewide jurisdiction.

(b) An action for a declaratory judgment or injunctive relief may be brought in accordance with this section against a governmental body that violates this chapter.

(c) The district or county attorney for the county in which a governmental body other than a state agency is located or the attorney general may bring the action in the name of the state only in a district court for that county. If the governmental body extends into more than one county, the action may be brought only in the county in which the administrative offices of the governmental body are located.

(d) If the governmental body is a state agency, the Travis County district attorney or the attorney general may bring the action in the name of the state only in a district court of Travis County.

(e) A complainant may file a complaint alleging a violation of this chapter. The complaint must be filed with the district or county attorney of the county in which the governmental body is located unless the governmental body is the district or county attorney. If the governmental body extends into more than one county, the complaint must be filed with the district or county attorney of the county in which the administrative offices of the governmental body are located. If the governmental body is a state agency, the complaint may be filed with the Travis County district attorney. If the governmental body is the district or county attorney, the complaint must be filed with the attorney general. To be valid, a complaint must:

(1) be in writing and signed by the complainant;

(2) state the name of the governmental body that allegedly committed the violation, as accurately as can be done by the complainant;

(3) state the time and place of the alleged commission of the violation, as definitely as can be done by the complainant; and

(4) in general terms, describe the violation.

(f) A district or county attorney with whom the complaint is filed shall indicate on the face of the written complaint the date the complaint is filed.

(g) Before the 31st day after the date a complaint is filed under Subsection (e), the district or county attorney shall:

(1) determine whether:

(A) the violation alleged in the complaint was committed; and

(B) an action will be brought against the governmental body under this section; and

(2) notify the complainant in writing of those determinations.

(h) Notwithstanding Subsection (g)(1), if the district or county attorney believes that that official has a conflict of interest that would preclude that official from bringing an action under this section against the governmental body complained of, before the 31st day after the date the complaint was filed the county or district attorney shall inform the complainant of that official's belief and of the complainant's right to file the complaint with the attorney general. If the district or county attorney determines not to bring an action under this section, the district or county attorney shall:

(1) include a statement of the basis for that determination; and

(2) return the complaint to the complainant.

(i) If the district or county attorney determines not to bring an action under this section, the complainant is entitled

to file the complaint with the attorney general before the 31st day after the date the complaint is returned to the complainant. A complainant is entitled to file a complaint with the attorney general on or after the 90th day after the date the complainant files the complaint with a district or county attorney if the district or county attorney has not brought an action under this section. On receipt of the written complaint, the attorney general shall comply with each requirement in Subsections (g) and (h) in the time required by those subsections. If the attorney general decides to bring an action under this section against a governmental body located only in one county in response to the complaint, the attorney general must comply with Subsection (c).

(j) An action may be brought under this section only if the official proposing to bring the action notifies the governmental body in writing of the official's determination that the alleged violation was committed and the governmental body does not cure the violation before the fourth day after the date the governmental body receives the notice.

(k) An action authorized by this section is in addition to any other civil, administrative, or criminal action provided by this chapter or another law.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 28, eff. Sept. 1, 1999. Amended by: Acts 2017, 85th Leg., R.S., Ch. 894 (H.B. 3107), Sec. 4, eff. September 1, 2017.

Sec. 552.322. DISCOVERY OF INFORMATION UNDER PROTECTIVE ORDER PENDING FINAL DETERMINATION. In a suit filed under this chapter, the court may order that the information at issue may be discovered only under a protective order until a final determination is made.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993.

Sec. 552.3221. IN CAMERA INSPECTION OF INFORMATION. (a) In any suit filed under this chapter, the information at issue may be filed with the court for in camera inspection as is necessary for the adjudication of the case.

(b) Upon receipt of the information at issue for in camera inspection, the court shall enter an order that prevents release to or access by any person other than the court, a reviewing court of appeals, or parties permitted to inspect the information pursuant to a protective order. The order shall further note the filing date and time.

(c) The information at issue filed with the court for in camera inspection shall be:

(1) appended to the order and transmitted by the court to the clerk for filing as "information at issue";

(2) maintained in a sealed envelope or in a manner that precludes disclosure of the information; and

(3) transmitted by the clerk to any court of appeal as part of the clerk's record.

(d) Information filed with the court under this section does not constitute "court records" within the meaning of Rule 76a, Texas Rules of Civil Procedure, and shall not be made available by the clerk or any custodian of record for public inspection.

(e) For purposes of this section, "information at issue" is defined as information held by a governmental body that forms the basis of a suit under this chapter.

Added by Acts 2013, 83rd Leg., R.S., Ch. 461 (S.B. 983), Sec. 1, eff. September 1, 2013.

Sec. 552.323. ASSESSMENT OF COSTS OF LITIGATION AND REASONABLE ATTORNEY FEES. (a) In an action brought under Section 552.321 or 552.3215, the court shall assess costs of litigation and reasonable attorney fees incurred by a plaintiff who substantially prevails, except that the court may not assess those costs and fees against a governmental body if the court

finds that the governmental body acted in reasonable reliance on:

(1) a judgment or an order of a court applicable to the governmental body;

(2) the published opinion of an appellate court; or

(3) a written decision of the attorney general, including a decision issued under Subchapter G or an opinion issued under Section 402.042.

(b) In an action brought under Section 552.324, the court may not assess costs of litigation or reasonable attorney's fees incurred by a plaintiff or defendant who substantially prevails unless the court finds the action or the defense of the action was groundless in fact or law. In exercising its discretion under this subsection, the court shall consider whether the conduct of the governmental body had a reasonable basis in law and whether the litigation was brought in good faith.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1999, 76th Leg., ch. 1319, Sec. 29, eff. Sept. 1, 1999. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 9, eff. September 1, 2009; Acts 2019, 86th Leg., R.S., Ch. 616 (S.B. 988), Sec. 1, eff. September 1, 2019.

Sec. 552.324. SUIT BY GOVERNMENTAL BODY. (a) The only suit a governmental body may file seeking to withhold information from a requestor is a suit that:

(1) is filed in a Travis County district court against the attorney general in accordance with Section 552.325; and

(2) seeks declaratory relief from compliance with a decision by the attorney general issued under Subchapter G.

(b) The governmental body must bring the suit not later than the 30th calendar day after the date the governmental body receives the decision of the attorney general determining that the requested information must be disclosed to the requestor. If the governmental body does not bring suit within that period,

the governmental body shall comply with the decision of the attorney general. If a governmental body wishes to preserve an affirmative defense for its officer for public information as provided in Section 552.353(b)(3), suit must be filed within the deadline provided in Section 552.353(b)(3).

Added by Acts 1995, 74th Leg., ch. 578, Sec. 1, eff. Aug. 28, 1995; Acts 1995, 74th Leg., ch. 1035, Sec. 24, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 165, Sec. 13.01, eff. Sept. 1, 1997; Acts 1997, 75th Leg., ch. 1231, Sec. 9, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 1319, Sec. 30, eff. Sept. 1, 1999. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 10, eff. September 1, 2009.

Sec. 552.325. PARTIES TO SUIT SEEKING TO WITHHOLD INFORMATION. (a) A governmental body, officer for public information, or other person or entity that files a suit seeking to withhold information from a requestor may not file suit against the person requesting the information. The requestor is entitled to intervene in the suit.

(b) The governmental body, officer for public information, or other person or entity that files the suit shall demonstrate to the court that the governmental body, officer for public information, or other person or entity made a timely good faith effort to inform the requestor, by certified mail or by another written method of notice that requires the return of a receipt, of:

(1) the existence of the suit, including the subject matter and cause number of the suit and the court in which the suit is filed;

(2) the requestor's right to intervene in the suit or to choose to not participate in the suit;

(3) the fact that the suit is against the attorney general in Travis County district court; and

(4) the address and phone number of the office of the attorney general.

(c) If the attorney general enters into a proposed settlement that all or part of the information that is the subject of the suit should be withheld, the attorney general shall notify the requestor of that decision and, if the requestor has not intervened in the suit, of the requestor's right to intervene to contest the withholding. The attorney general shall notify the requestor:

(1) in the manner required by the Texas Rules of Civil Procedure, if the requestor has intervened in the suit; or

(2) by certified mail or by another written method of notice that requires the return of a receipt, if the requestor has not intervened in the suit.

(d) The court shall allow the requestor a reasonable period to intervene after the attorney general attempts to give notice under Subsection (c)(2).

Added by Acts 1995, 74th Leg., ch. 578, Sec. 1, eff. Aug. 28, 1995; Acts 1995, 74th Leg., ch. 1035, Sec. 24, eff. Sept. 1, 1995. Amended by Acts 1997, 75th Leg., ch. 165, Sec. 13.01, eff. Sept. 1, 1997; Acts 1997, 75th Leg., ch. 1231, Sec. 9, eff. Sept. 1, 1997. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 11, eff. September 1, 2009.

Sec. 552.326. FAILURE TO RAISE EXCEPTIONS BEFORE ATTORNEY GENERAL. (a) Except as provided by Subsection (b), the only exceptions to required disclosure within Subchapter C that a governmental body may raise in a suit filed under this chapter are exceptions that the governmental body properly raised before the attorney general in connection with its request for a decision regarding the matter under Subchapter G.

(b) Subsection (a) does not prohibit a governmental body from raising an exception:

(1) based on a requirement of federal law; or

(2) involving the property or privacy interests of another person.

Added by Acts 1999, 76th Leg., ch. 1319, Sec. 31, eff. Sept. 1, 1999.

Sec. 552.327. DISMISSAL OF SUIT DUE TO REQUESTOR'S WITHDRAWAL OR ABANDONMENT OF REQUEST. A court may dismiss a suit challenging a decision of the attorney general brought in accordance with this chapter if:

(1) all parties to the suit agree to the dismissal; and

(2) the attorney general determines and represents to the court that the requestor has voluntarily withdrawn the request for information in writing or has abandoned the request.

Added by Acts 2007, 80th Leg., R.S., Ch. 474 (H.B. 2248), Sec. 2, eff. September 1, 2007.

SUBCHAPTER I. CRIMINAL VIOLATIONS

Sec. 552.351. DESTRUCTION, REMOVAL, OR ALTERATION OF PUBLIC INFORMATION. (a) A person commits an offense if the person wilfully destroys, mutilates, removes without permission as provided by this chapter, or alters public information.

(b) An offense under this section is a misdemeanor punishable by:

(1) a fine of not less than $25 or more than $4,000;

(2) confinement in the county jail for not less than three days or more than three months; or

(3) both the fine and confinement.

(c) It is an exception to the application of Subsection (a) that the public information was transferred under Section 441.204.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 25, eff.

Sept. 1, 1995; Acts 2001, 77th Leg., ch. 771, Sec. 2, eff. June 13, 2001.

Sec. 552.352. DISTRIBUTION OR MISUSE OF CONFIDENTIAL INFORMATION. (a) A person commits an offense if the person distributes information considered confidential under the terms of this chapter.

(a-1) An officer or employee of a governmental body who obtains access to confidential information under Section 552.008 commits an offense if the officer or employee knowingly:

(1) uses the confidential information for a purpose other than the purpose for which the information was received or for a purpose unrelated to the law that permitted the officer or employee to obtain access to the information, including solicitation of political contributions or solicitation of clients;

(2) permits inspection of the confidential information by a person who is not authorized to inspect the information; or

(3) discloses the confidential information to a person who is not authorized to receive the information.

(a-2) For purposes of Subsection (a-1), a member of an advisory committee to a governmental body who obtains access to confidential information in that capacity is considered to be an officer or employee of the governmental body.

(b) An offense under this section is a misdemeanor punishable by:

(1) a fine of not more than $1,000;

(2) confinement in the county jail for not more than six months; or

(3) both the fine and confinement.

(c) A violation under this section constitutes official misconduct.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 2003, 78th Leg., ch. 249, Sec. 7.01,

7.02, eff. Sept. 1, 2003; Acts 2003, 78th Leg., ch. 1089, Sec. 2, eff. Sept. 1, 2003.

Sec. 552.353. FAILURE OR REFUSAL OF OFFICER FOR PUBLIC INFORMATION TO PROVIDE ACCESS TO OR COPYING OF PUBLIC INFORMATION. (a) An officer for public information, or the officer's agent, commits an offense if, with criminal negligence, the officer or the officer's agent fails or refuses to give access to, or to permit or provide copying of, public information to a requestor as provided by this chapter.

(b) It is an affirmative defense to prosecution under Subsection (a) that the officer for public information reasonably believed that public access to the requested information was not required and that:

(1) the officer acted in reasonable reliance on a court order or a written interpretation of this chapter contained in an opinion of a court of record or of the attorney general issued under Subchapter G;

(2) the officer requested a decision from the attorney general in accordance with Subchapter G, and the decision is pending; or

(3) not later than the 10th calendar day after the date of receipt of a decision by the attorney general that the information is public, the officer or the governmental body for whom the defendant is the officer for public information filed a petition for a declaratory judgment against the attorney general in a Travis County district court seeking relief from compliance with the decision of the attorney general, as provided by Section 552.324, and the cause is pending.

(c) It is an affirmative defense to prosecution under Subsection (a) that a person or entity has, not later than the 10th calendar day after the date of receipt by a governmental body of a decision by the attorney general that the information is public, filed a cause of action seeking relief from

compliance with the decision of the attorney general, as provided by Section 552.325, and the cause is pending.

(d) It is an affirmative defense to prosecution under Subsection (a) that the defendant is the agent of an officer for public information and that the agent reasonably relied on the written instruction of the officer for public information not to disclose the public information requested.

(e) An offense under this section is a misdemeanor punishable by:

(1) a fine of not more than $1,000;

(2) confinement in the county jail for not more than six months; or

(3) both the fine and confinement.

(f) A violation under this section constitutes official misconduct.

Added by Acts 1993, 73rd Leg., ch. 268, Sec. 1, eff. Sept. 1, 1993. Amended by Acts 1995, 74th Leg., ch. 1035, Sec. 25, eff. Sept. 1, 1995. Amended by: Acts 2009, 81st Leg., R.S., Ch. 1377 (S.B. 1182), Sec. 12, eff. September 1, 2009.

SUBCHAPTER J. ADDITIONAL PROVISIONS RELATED TO CONTRACTING INFORMATION

Sec. 552.371. CERTAIN ENTITIES REQUIRED TO PROVIDE CONTRACTING INFORMATION TO GOVERNMENTAL BODY IN CONNECTION WITH REQUEST. (a) This section applies to an entity that is not a governmental body that executes a contract with a governmental body that:

(1) has a stated expenditure of at least $1 million in public funds for the purchase of goods or services by the governmental body; or

(2) results in the expenditure of at least $1 million in public funds for the purchase of goods or services by the governmental body in a fiscal year of the governmental body.

(b) This section applies to a written request for public information received by a governmental body that is a party to a contract described by Subsection (a) for contracting information related to the contract that is in the custody or possession of the entity and not maintained by the governmental body.

(c) A governmental body that receives a written request for information described by Subsection (b) shall request that the entity provide the information to the governmental body. The governmental body must send the request in writing to the entity not later than the third business day after the date the governmental body receives the written request described by Subsection (b).

(d) Notwithstanding Section 552.301:

(1) a request for an attorney general's decision under Section 552.301(b) to determine whether contracting information subject to a written request described by Subsection (b) falls within an exception to disclosure under this chapter is considered timely if made not later than the 13th business day after the date the governmental body receives the written request described by Subsection (b);

(2) the statement and copy described by Section 552.301(d) is considered timely if provided to the requestor not later than the 13th business day after the date the governmental body receives the written request described by Subsection (b);

(3) a submission described by Section 552.301(e) is considered timely if submitted to the attorney general not later than the 18th business day after the date the governmental body receives the written request described by Subsection (b); and

(4) a copy described by Section 552.301(e-1) is considered timely if sent to the requestor not later than the 18th business day after the date the governmental body receives the written request described by Subsection (b).

(e) Section 552.302 does not apply to information described by Subsection (b) if the governmental body:

(1) complies with the requirements of Subsection (c) in a good faith effort to obtain the information from the contracting entity;

(2) is unable to meet a deadline described by Subsection (d) because the contracting entity failed to provide the information to the governmental body not later than the 13th business day after the date the governmental body received the written request for the information; and

(3) if applicable and notwithstanding the deadlines prescribed by Sections 552.301(b), (d), (e), and (e-1), complies with the requirements of those subsections not later than the eighth business day after the date the governmental body receives the information from the contracting entity.

(f) Nothing in this section affects the deadlines or duties of a governmental body under Section 552.301 regarding information the governmental body maintains, including contracting information.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

Sec. 552.372. BIDS AND CONTRACTS. (a) A contract described by Section 552.371 must require a contracting entity to:

(1) preserve all contracting information related to the contract as provided by the records retention requirements applicable to the governmental body for the duration of the contract;

(2) promptly provide to the governmental body any contracting information related to the contract that is in the custody or possession of the entity on request of the governmental body; and

(3) on completion of the contract, either:

(A) provide at no cost to the governmental body all contracting information related to the contract that is in the custody or possession of the entity; or

(B) preserve the contracting information related to the contract as provided by the records retention requirements applicable to the governmental body.

(b) Unless Section 552.374(c) applies, a bid for a contract described by Section 552.371 and the contract must include the following statement: "The requirements of Subchapter J, Chapter 552, Government Code, may apply to this (include "bid" or "contract" as applicable) and the contractor or vendor agrees that the contract can be terminated if the contractor or vendor knowingly or intentionally fails to comply with a requirement of that subchapter."

(c) A governmental body may not accept a bid for a contract described by Section 552.371 or award the contract to an entity that the governmental body has determined has knowingly or intentionally failed to comply with this subchapter in a previous bid or contract described by that section unless the governmental body determines and documents that the entity has taken adequate steps to ensure future compliance with the requirements of this subchapter.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

Sec. 552.373. NONCOMPLIANCE WITH PROVISION OF SUBCHAPTER. A governmental body that is the party to a contract described by Section 552.371 shall provide notice to the entity that is a party to the contract if the entity fails to comply with a requirement of this subchapter applicable to the entity. The notice must:

(1) be in writing;

(2) state the requirement of this subchapter that the entity has violated; and

(3) unless Section 552.374(c) applies, advise the entity that the governmental body may terminate the contract without further obligation to the entity if the entity does not

cure the violation on or before the 10th business day after the date the governmental body provides the notice.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

Sec. 552.374. TERMINATION OF CONTRACT FOR NONCOMPLIANCE. (a) Subject to Subsection (c), a governmental body may terminate a contract described by Section 552.371 if:

(1) the governmental body provides notice under Section 552.373 to the entity that is party to the contract;

(2) the contracting entity does not cure the violation in the period prescribed by Section 552.373;

(3) the governmental body determines that the contracting entity has intentionally or knowingly failed to comply with a requirement of this subchapter; and

(4) the governmental body determines that the entity has not taken adequate steps to ensure future compliance with the requirements of this subchapter.

(b) For the purpose of Subsection (a), an entity has taken adequate steps to ensure future compliance with this subchapter if:

(1) the entity produces contracting information requested by the governmental body that is in the custody or possession of the entity not later than the 10th business day after the date the governmental body makes the request; and

(2) the entity establishes a records management program to enable the entity to comply with this subchapter.

(c) A governmental body may not terminate a contract under this section if the contract is related to the purchase or underwriting of a public security, the contract is or may be used as collateral on a loan, or the contract's proceeds are used to pay debt service of a public security or loan.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

Sec. 552.375. OTHER CONTRACT PROVISIONS. Nothing in this subchapter prevents a governmental body from including and enforcing more stringent requirements in a contract to increase accountability or transparency.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

Sec. 552.376. CAUSE OF ACTION NOT CREATED. This subchapter does not create a cause of action to contest a bid for or the award of a contract with a governmental body.

Added by Acts 2019, 86th Leg., R.S., Ch. 1216 (S.B. 943), Sec. 9, eff. January 1, 2020.

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 1 PRACTICE AND PROCEDURE
SUBCHAPTER A DEFINITIONS AND GENERAL PROVISIONS

§1.1 Purpose, Scope, and Conflict with Other Rules

(a) This chapter establishes a system for practice and procedure before the Railroad Commission of Texas to enable the just disposition of proceedings and public participation in contested case proceedings pursuant to the Administrative Procedure Act, Texas Government Code, Chapter 2001.

(b) This chapter governs the institution, conduct, and determination of Commission proceedings required or permitted by law, whether instituted by order of the Commission or by filing an application, complaint, petition, or other pleading. This chapter does not and shall not be construed to enlarge, diminish, modify, or otherwise alter the jurisdiction, powers, or authority of the Commission or the substantive rights of any person or agency.

(c) It is the policy of the Commission to encourage the fair and prompt resolution of internal and external disputes under the Commission's jurisdiction through alternative dispute resolution (ADR). ADR includes any procedure or combination of procedures described by Texas Civil Practice and Remedies Code Chapter 154, such as mediation, arbitration, and mini-trial.

(d) This chapter sets forth the general rules of practice and procedure for proceedings before the Commission. If a general provision of these rules conflicts with a statutory or other special provision governing the same proceeding, and the conflict is irreconcilable, then the special provision controls.

Source Note: The provisions of this §1.1 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.2 Definitions

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

(1) Agency--A board, commission, department, or other entity created under Texas law that has statewide jurisdiction and makes rules or determines contested cases, other than an agency wholly funded by federal appropriations, the legislature, the courts, and institutions of higher education.

(2) APA--The Administrative Procedure Act, Texas Government Code, Chapter 2001, as it may be amended.

(3) Applicant--A person who by written application, including appeals, seeks a remedy from the Commission.

(4) Authorized representative--The individual designated in writing as representing any person or party before the Commission pursuant to these rules, including an attorney authorized to practice law in the State of Texas.

(5) Business day--A calendar day that is not a Saturday, Sunday, or official state or federal holiday.

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

(7) Commissioner--One of the elected or appointed members of the Railroad Commission of Texas.

(8) Complainant--A person who files a complaint with the Commission as specified in §1.23 of this title (relating to Complaint Proceedings), regarding an act or omission of the Commission or a person subject to the Commission's jurisdiction.

(9) Contested case--A proceeding in which the legal rights, duties, or privileges of a party are to be determined by the Commission pursuant to the APA after an opportunity for adjudicative hearing, as specified in Subchapter G of this chapter (relating to Hearings).

(10) Director--The individual appointed by the Commission who is in charge of a division or section within the Commission. Subject to Commission directive or other Commission rules, a director may delegate the director's authority to another Commission employee.

(11) Division--An operating or administrative unit of the Commission.

(12) Docket--To assign a docket number to and create a file for a contested case.

(13) Docket number--A reference number assigned by the appropriate division or the Hearings Division to a contested case and used to identify that case.

(14) Docket Services Section--The section within the Hearings Division, under the supervision of the Hearings Director, that administers docketed cases pursuant to this chapter.

(15) Examiner or hearings examiner--An individual appointed by the Commission to conduct hearings, including an administrative law judge, a technical examiner, and other designated employees of the Commission.

(16) Final order--The Commission's final written disposition of a contested case, whether affirmative, negative, injunctive, or declaratory.

(17) Hearings Division--The division responsible for scheduling, conducting, and preparing recommendations on hearings concerning matters within the Commission's jurisdiction.

(18) Intervenor--A person, other than an applicant, complainant, petitioner, protestant, or respondent, who is admitted as a party to a contested case pursuant to §1.37 of this title (relating to Intervention).

(19) License--The whole or a part of a permit, certificate, approval, registration, or similar form of permission issued or granted by the Commission.

(20) Office of General Counsel--The division responsible for providing legal advice to the Commission, comprising the Enforcement Section and the General Counsel Section.

(21) Party--A person named or admitted as an applicant, complainant, petitioner, intervenor, protestant, or respondent in a contested case before the Commission.

(22) Person--An individual, corporation, business trust, estate, trust, partnership, limited liability company, association, joint venture, government, governmental subdivision, agency, instrumentality, public corporation, or any other legal or commercial entity.

(23) Petitioner--A person who by written petition, including appeals, seeks a remedy from the Commission.

(24) Pleading--A written document submitted in a contested case by a person or authorized representative setting forth allegations of fact, legal arguments, claims, requests for relief, or other matters. Pleadings may take the form of applications, petitions, complaints, protests, exceptions, replies, motions, responses or answers, or other requests for action.

(25) Proceeding--A formal hearing, investigation, inquiry, rulemaking, or other fact-finding or decision-making

process.

(26) Protestant--A person opposing an application or petition submitted to the Commission.

(27) Protested contested case--A contested case in which a party appears and contests or opposes the relief sought, including relief sought in applications, petitions, show-cause proceedings, or complaints.

(28) Register--The Texas Register established by Acts of 1975, 64th Legislature, codified in Texas Government Code, Chapter 2002.

(29) Respondent--A person against whom any complaint has been filed, who is under formal investigation by the Commission, or who is the subject of a show-cause proceeding.

(30) Rule--A Commission statement of general applicability that implements, interprets, or prescribes law or policy, or that describes the Commission's procedure or practice requirements. The term includes a newly adopted rule and the amendment or repeal of an existing a rule but does not include statements concerning only the internal management or organization of the Commission and not affecting private rights or procedures.

(31) Rulemaking--The process to adopt a new rule or to amend or repeal an existing rule pursuant to Texas law.

(32) Show-cause proceeding--A formal opportunity for a respondent to present evidence challenging allegations made against the respondent or to oppose a proposed action concerning the respondent.

(33) Telephony--Includes conventional telephonic communication, Voice over Internet Protocol (VoIP) communication, and all forms of digital audio and audio/video tele-conferencing.

Source Note: The provisions of this §1.2 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.3 Exceptions and Suspension of Rules

(a) The Commission, the Hearings Director, or the examiner may grant exceptions to the provisions of this chapter upon a showing of good cause and if necessary in the interest of justice.

(b) The Commission may suspend the operation of one or more of its general or special rules of practice and procedure if it finds that there exists a public emergency or imperative public necessity.

(c) The Commission may waive any fee established by one or more of its general or special rules of practice and procedure for good cause shown, except those fees required by statute.

Source Note: The provisions of this §1.3 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.4 Violation of Procedural Rules

In addition to any other penalties authorized by law or by Commission rule, the violation of any general or special rule of practice and procedure shall be sufficient cause for the Commissioners, after notice and hearing, to enter an order holding the offender in contempt or subjecting the offender to just, reasonable, and lawful disciplinary action.

Source Note: The provisions of this §1.4 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.5 Conduct and Decorum

Parties, authorized representatives, witnesses, and other participants in Commission proceedings shall conduct themselves with proper dignity, courtesy, civility, and respect for the Commission, the director, the examiner, and all other participants. Disorderly conduct will not be tolerated. A violator of this rule may be excluded from the proceeding by the examiner for such period as is just and may be subject to such other just, reasonable, and lawful disciplinary action as the Commission may prescribe.

Source Note: The provisions of this §1.5 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.6 Recording and Broadcasting of Hearings

Coverage of a hearing through broadcasting, televising, recording, live-streaming, or photographing is permitted upon prior approval of the Hearings Director. The request for approval shall specify the type of coverage to be conducted at the hearing. Requests may be denied or approved with restrictions if the Hearings Director finds coverage will unduly distract participants, interfere with the hearings process, or impair the dignity of the hearing.

Source Note: The provisions of this §1.6 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.7 Ex Parte Communications

(a) Ex parte communications are prohibited in contested cases as provided in the APA and other applicable rules including the Texas Disciplinary Rules of Professional Conduct.

(b) Each party shall provide all other parties with a copy of all documents submitted to an examiner.

(1) The attachment of a certificate of service stating that a document was served on a party creates a rebuttable presumption that the named party was provided a copy.

(2) Failure to provide a copy to all other parties may result in rejection and return of the document without consideration.

Source Note: The provisions of this §1.7 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.8 Testimony under Oath or Affirmation

Testimony in all contested cases shall be presented under oath or affirmation administered by an examiner, Commissioner, or court reporter.

Source Note: The provisions of this §1.8 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.9 Computation and Extensions of Time in Contested Cases

(a) In computing any period of time prescribed or permitted by the Hearings Director, the examiner, a rule or an order of the Commission, or any applicable statute:

(1) the day of the act, event, or default from which the period of time begins to run shall not be included;

(2) the last day of the period being computed shall be included, unless it is a Saturday, Sunday, weekday on which the Commission has officially closed prior to 5 p.m. due to weather or other exigency, or an official state or federal holiday, in which event the period shall continue to run until 5 p.m. on the next business day except as otherwise provided by statute; and

(3) Saturdays, Sundays, and official state or federal holidays shall not be counted for any purpose in any time period of five days or less in these rules.

(b) Unless otherwise provided by statute or special rule, the time for filing any pleading or other document may be extended upon the granting of a motion for extension of time. The motion shall:

(1) be filed with the Docket Services Section prior to the applicable deadline;

(2) show that there is good cause for an extension of time and that the need for the extension is not caused by the negligence, indifference, or lack of diligence of the person, party, or authorized representative filing the motion; and

(3) be served in accordance with §1.45 of this title (relating to Service in Protested Contested Cases).

Source Note: The provisions of this §1.9 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.10 Commissioner Private Interest in Decision

(a) A Commissioner with a personal or private interest in a measure, proposal or decision pending before the Commission shall publicly disclose the fact to the Commission in an open meeting. The Commissioner may not vote or otherwise participate in the decision. The disclosure shall be entered in the minutes of the meeting.

(b) In this section, "personal or private interest" has the same meaning as is given to it under Texas Government Code, §572.058.

Source Note: The provisions of this §1.10 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER B INITIATION OF CONTESTED CASE PROCEEDING

§1.21 Filings with Commission Division Directors

(a) All applications, petitions, complaints, and other documents relating to any proceeding to be initiated before the Commission shall be filed with the appropriate division director in accordance with that division's filing requirements and any applicable statute or regulation. Such documents, including notices of protest and answers, shall be presumed filed on the date they are actually received only if accompanied by any required filing fee. The Commission may decline to accept a document for filing if it does not comply with applicable requirements.

(b) If an application, petition, complaint, or other document requires further consideration after division processing but prior to final Commission action, the division shall transfer the matter to the Hearings Division.

Source Note: The provisions of this §1.21 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.22 Filings with the Hearings Division

(a) Once a party has notice that a division has transferred a contested case to the Hearings Division, the party shall file all subsequent pleadings and other documents related to the case with the Docket Services Section.

(b) Pleadings and related documents filed with the Hearings Division shall be deemed filed only when they are actually received by the Docket Services Section and are accompanied by any required filing fee. The time and date of filing shall be determined by the file stamp affixed on the pleading or related document by the Docket Services Section.

(c) Except as provided in subsection (e) of this section, pleadings shall be filed as follows:

(1) If the pleading contains 10 or fewer pages including exhibits, it may be filed by fax, email, or other approved electronic transmission with the Docket Services Section. If a party or authorized representative elects to file a pleading by email, the party or authorized representative agrees to be served by email and affirmatively consents to the release and disclosure of the email address.

(2) Pleadings longer than 10 pages shall be filed in hard copy with the Docket Services Section, unless the examiner or Hearings director informs the parties in writing that they may file all documents pursuant to paragraph (1) of this subsection.

(d) Unless the examiner sets the filing deadline at a time earlier than 5 p.m., pleadings and related documents shall be considered timely filed if received and file stamped by the Docket Services Section on or before 5 p.m. of the filing deadline. Pleadings filed after 5 p.m. local time of the Commission shall be deemed filed the following business day. Pleadings filed by fax, email, or other approved electronic transmission shall be considered filed at or before 5 p.m. local time if the complete pleading is received at or before 5 p.m. local time. If the examiner sets the filing deadline at a time earlier than 5 p.m., pleadings and related documents shall be considered filed at the time indicated by the file stamp.

(e) Exceptions and replies, and motions for rehearing and replies to motions for rehearing shall be filed pursuant to §1.122 of this title (relating to Filing of Exceptions and Replies) and §1.128 of this title (relating to Motions for Rehearing), respectively.

(f) The Hearings Division may decline to accept a transferred case, docket a case, accept a filing, or set a hearing in instances where there has been a failure to substantially conform to the rules in this chapter.

Source Note: The provisions of this §1.22 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.23 Complaint Proceedings

(a) Filing of complaint. Complaints relating to matters within the Commission's jurisdiction shall be in writing and contain a detailed description of the allegations against the respondent. The complainant shall serve the complaint on the respondent and simultaneously file it with the applicable division of the Commission. The division receiving the complaint shall transfer it to the Hearings Division. If the complainant amends the complaint, the complainant shall serve the amended complaint on the respondent and simultaneously file it with the Docket Services Section.

(b) Burden of proof. The complainant in a complaint proceeding shall have the burden of proof which is a preponderance of the evidence. In the interest of justice, the examiner may modify the burden of proof pursuant to §1.110 of this title (relating to Burden of Proof).

(c) Notice of complaint. When a complaint is filed, the Commission shall forward the complaint to the respondent and attach a letter stating:

(1) the respondent has 20 days from the date of the letter to either file an answer or request a hearing to contest the allegations of the original complaint; and

(2) that a default order may be entered against the respondent if the respondent fails to answer, request a hearing, or appear at the hearing, if a hearing is requested.

(d) Respondent's answer.

(1) The respondent shall answer the complaint in writing, by either specifically denying the material allegations of the complaint or alleging an affirmative defense. Alternatively, the respondent may request a hearing which shall serve as a general denial of the allegations in the original complaint.

(2) If the complaint is thereafter amended, the time

period for the filing and service of the answer shall, unless otherwise ordered, run from the service of such amended complaint. The original answer shall be considered as the answer to the amended complaint unless a new answer is filed in response to the amended complaint.

(e) Default order. If the respondent fails to answer, request a hearing, or appear at the hearing, the examiner may find the respondent to be in default and prepare a default final order to be presented to the Commission without further notice.

(f) Dismissal for lack of jurisdiction of Commission or standing of complainant.

(1) If the Commission finds, either on the face of the complaint or after motion of the respondent, that the Commission lacks jurisdiction or the complainant lacks standing, the Hearings Director or the Commissioners shall dismiss the complaint as to such allegation or complainant.

(2) Any dismissal order entered by the Hearings Director is subject to review by an appeal to the Commissioners. The appeal shall follow the same requirements set forth in §1.38(e) of this title (relating to Interim Rulings and Appeals of Interim Rulings).

(g) Retail customers served by a gas utility as defined in Texas Utilities Code §§101.003(7), (8), and 121.001 - 121.006, must first attempt an informal resolution pursuant to §7.45 of this title (relating to Quality of Service) before pursuing a claim against a gas utility under this section.
Source Note: The provisions of this §1.23 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.24 Show-Cause Proceedings

(a) In response to a written complaint or on the Commission's own motion, the Commission or the Hearings Director may issue a notice commanding a person subject to the Commission's jurisdiction to appear at a public hearing and show cause why the person should not be compelled to do the act required, or refrain from doing an act, or why the Commission should not take the proposed action.

(b) The respondent in a show-cause proceeding shall have the burden of proof which is a preponderance of the evidence.

(c) On the respondent's failure to appear at the hearing or meet its burden of proof, the respondent may be compelled to do the act required or to refrain from doing an act, or the Commission may take the proposed action.
Source Note: The provisions of this §1.24 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.25 Contested Cases Brought by the Enforcement Section

(a) Commencement of a contested case.

(1) Enforcement contested cases are commenced when a division of the Commission refers the matter to the Enforcement Section of the Office of General Counsel and the Enforcement Section assigns a docket number to the case. Before filing a complaint, the Commission may offer to settle the case through an agreed order.

(2) If the Commission does not offer to settle, or the terms of the offer are not timely met by the respondent, the Commission will send the original complaint to the respondent by certified and regular first-class mail. In cases against foreign or non-resident respondents, the complaint will also be sent to the resident agent listed on the respondent's most recently filed Organization Report (Form P-5). The complaint will be accompanied by a letter alleging that the respondent has violated Commission rules or statutes as set forth in the original complaint; that the respondent may, within 30 days of the date of service, file an answer or request a hearing to contest the allegations of the original complaint; and that the respondent may wish to hire an attorney or other authorized representative or choose to appear on its own behalf. The letter will notify the respondent that if, on 31st day after the date of service, it has not entered into an agreed order, filed an answer to the original complaint, or requested a hearing, a default final order may thereafter be issued against respondent without further notice. Concurrent with the complaint, the Commission may make an offer to settle the case through an agreed order.

(3) When there is actual pollution or injury to the public health and safety, or an imminent threat thereof, a hearing may be set and notice of the hearing sent with the original complaint. The notice will state that if the respondent fails to appear at the hearing, a default final order may be issued against respondent without further notice as specified in subsection (d) of this section.

(b) Filing of answer or request for hearing; setting of hearing. A request for hearing made by the respondent shall serve as a general denial of the allegations in the original complaint. An answer or request for hearing is timely if filed with the Docket Services Section before the matter is included on an open meeting agenda of the Commission that has been posted with the Secretary of State. Except in cases brought under subsection (a)(3) of this section, the Enforcement Section will coordinate with the Docket Services Section to set a hearing on a date at least 30 days after receipt of a timely answer or hearing request, unless the case is disposed of by other means.

(c) Notice of hearing. Notices of hearing will be sent along with the original complaint to respondents or their authorized representatives in all cases brought under subsection (a)(3) of this section. In all other cases, notices of hearing will be sent, along with a current Enforcement Section pleading, only after the respondent or its authorized representative has timely filed a request for hearing or an answer. The notice will be sent to the address from which the request or answer was received, and will state that if the respondent fails to appear at the hearing, a default final order may be issued against respondent without further notice as specified in subsection (d) of this section.

(d) Default order upon failure to answer, request hearing, or appear at hearing.

(1) If the respondent fails to timely answer the original complaint, request a hearing, or appear at a scheduled hearing, a default final order may be issued by the Commission without further notice.

(2) Default final orders will contain findings of fact and conclusions of law sufficient to support the relief ordered.

(3) No default final order shall be issued until the Commission has access to the proof of service of the original complaint or the notice of hearing, or the returned certified mail containing the complaint or the notice, has been on file with the Commission for 15 days, exclusive of the day of receipt and day of issuance. Default final orders need not be individually signed in each case by the Commissioners if the case is listed by docket number and summarized on a Master Default Order.

(e) Non-applicability of this section to emergency situations. The existing power of the Commission to remedy

and seek reimbursement for remediation of any condition which threatens the public health and safety, or to order an operator to remedy said condition, shall not be affected by this section.

(f) When the Enforcement Section alleges a violation of Texas Natural Resources Code, §91.143, relating to false information filed with the Commission, if the records that are subject of the proceeding are incorrect, there is a presumption that the respondent filed the record knowing it to be incorrect. The presumption may be rebutted by competent evidence.

Source Note: The provisions of this §1.25 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.26 Classification and Alignment of Parties

(a) Parties to contested cases before the Commission are defined in §1.2 of this title (relating to Definitions). If there is an error in a party's designation in its pleadings, the examiner may assign a party an appropriate designation.

(b) The examiner may align parties according to the nature of the proceeding.

Source Note: The provisions of this §1.26 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.27 Parties and Authorized Representatives

(a) Any party may appear individually or through an authorized representative.

(b) Authorized representatives shall:

(1) file a notice of representation with the Docket Services Section that contains the representative's mailing address, telephone number, and, if applicable, fax number and email address;

(2) advise their clients and witnesses of applicable requirements of conduct and decorum;

(3) comply with §1.7 of this title (relating to Ex Parte Communications).

(c) If an authorized representative's authority is challenged, the authorized representative must file documents that evidence authority to appear as the party's representative.

(d) An authorized representative seeking to withdraw shall file a motion to withdraw and shall provide in the motion a mailing address, telephone number, and, if applicable, fax number and email address for the party or substitute representative. A party's authorized representative shall remain as such until the motion to withdraw is granted by the examiner.

(e) If an authorized representative includes an email address in the notice of representation, the authorized representative agrees to be served by email and affirmatively consents to the release and disclosure of the email address.

Source Note: The provisions of this §1.27 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER C PLEADINGS, MOTIONS, AND OTHER DOCUMENTS

§1.31 Classification of Pleadings

(a) Pleadings filed in contested case proceedings before the Commission shall be designated as one of the following: application, petition, complaint, notice of protest, answer, motion, exception, or response or reply to one of the preceding pleadings. If there is an error in the designation of a pleading, the examiner or the Hearings Director may determine the appropriate status in the proceeding and treat it accordingly.

(b) Requests for discovery and responses thereto shall not be classified as pleadings and shall become a part of the administrative record in a contested case only when offered as evidence, or when part of a request for an order compelling a discovery response, or a reply thereto.

(c) Pleadings shall be liberally construed. As applicable, the Commission, Hearings Director, or examiner may construe a document as a pleading if the intent of the filing or document is evident.

Source Note: The provisions of this §1.31 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.32 Form and Content of Pleadings

(a) Unless otherwise permitted or required by Commission rules or by statute, a pleading shall contain a statement of the pleading's objectives, a concise statement of supporting facts, and a specific request for relief.

(b) Pleadings that are filed in hard copy shall be printed on white paper that is 8 1/2 inches wide and 11 inches long, with at least one-inch margins, or on the appropriate Commission form. The text shall only be on one side of the paper and shall be double or one and one-half spaced, except that footnotes and lengthy quotations may be single spaced. Exhibits attached to a pleading shall be the same size as pleadings or folded to that size.

(c) Each pleading shall be signed by the party or its authorized representative. When a copy of the signed document has been filed, the party or its authorized representative shall maintain the original document for examination by the Commission, the examiner, the Hearings or appropriate division director, or any party to the proceedings, should a question arise as to its authenticity.

(d) A pleading shall contain:

(1) the filing party's business address, telephone number, and, if applicable, fax number or email address, or if filed by its authorized representative, the authorized representative's business address, telephone number, and, if applicable, the authorized representative's Texas state bar number, email address, and fax number; and

(2) a certification pursuant to §1.45 of this title (relating to Service in Protested Contested Cases).

(e) If a party or authorized representative includes its email address or fax number in a pleading, the party consents to be served by email or fax and affirmatively consents to the release and disclosure of the email address.

Source Note: The provisions of this §1.32 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.33 Correction of Pleadings

If the appropriate director or examiner finds that a pleading does not substantially comply in all material respects with the Commission's rules, notice of the deficiency or deficiencies will be provided to the filing party. Unless precluded by operation of law, the party who filed the pleading shall thereafter have the right to file a corrected pleading. The filing of a corrected pleading shall not be permitted to delay any proceeding unless the appropriate director or the examiner determines based on evidence submitted by the filing party that such delay is necessary to prevent an injustice or to protect the public interest.

Source Note: The provisions of this §1.33 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.34 Amended or Supplemental Pleadings

(a) Pleadings may be amended or supplemented when permitted by statute or when justice so requires.

(b) Unless the Commission, the Hearings Director, or the examiner approves and issues additional notice as required by law, an application, petition, or complaint, upon which original notice of hearing has been issued, may not be amended so as to broaden or enlarge the scope thereof.

Source Note: The provisions of this §1.34 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.35 Responsive Pleadings and Emergency Action

(a) Any responsive pleading shall be filed by a party within 10 days after filing of the pleading to which the response is made or as ordered by the examiner.

(b) A responsive pleading to a complaint filed under this chapter shall be filed by the respondent within 20 days of the date of the Commission's letter notifying the respondent of the complaint.

(c) The Commissioners, the Hearings Director, or the examiner may take action on a pleading before the deadline for filing responsive pleadings only in an emergency that presents a risk of imminent pollution, waste, or injury to persons or real or personal property. Action taken under such conditions is subject to modification based on a timely responsive pleading.

Source Note: The provisions of this §1.35 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.36 Motions

(a) A motion shall be filed with the Docket Services Section, unless dictated into the record during the pendency of a hearing, and shall state the relief sought and the specific reasons for the motion. If the motion is based upon alleged facts that are not a matter of record, it may, in the examiner's discretion, be supported by an affidavit. Motions shall be served in accordance with §1.45 of this title (relating to Service in Protested Contested Cases). Notice of action on any motion shall be served promptly on all parties.

(b) A motion is timely filed if filed with the Docket Services Section before the contested case is included on an open meeting agenda of the Commission that has been posted with the Secretary of State.

Source Note: The provisions of this §1.36 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.37 Intervention

(a) Any person who has a justiciable or administratively cognizable interest and who is not an applicant, petitioner, complainant, respondent, or protestant and who desires to be designated as a party in any contested case before the Commission may file a petition for leave to intervene no later than five days prior to the hearing date.

(b) The examiner or the Hearings Director shall promptly act on all petitions for leave to intervene. All interventions shall be subject to a motion to strike for having been improperly admitted.

Source Note: The provisions of this §1.37 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.38 Interim Rulings and Appeals of Interim Rulings

(a) Relief through interim ruling. Prior to presentation of a contested case to the Commission at an open meeting, a party may seek, through an examiner, or Hearings Director, as appropriate, relief through interim ruling, but that ruling shall not be considered of the same nature as a final decision. An interim ruling shall not be subject to exceptions or motions for rehearing. For purposes of this section, the term interim ruling includes orders issued pursuant to §1.55 of this title (relating to Discovery Orders) and final actions taken by Commission staff to deny an application or other requested relief for which no other avenue of appeal is provided by Commission rules.

(b) Evidentiary rulings. An evidentiary ruling by an examiner is not an interim ruling and is not appealable to the Commission pending the issuance by the examiner of a proposal for decision. Such rulings include, but are not limited to, reopening the record of a hearing for additional evidence, before a proposal for decision is issued.

(c) Interim ruling to suspend license.

(1) In this section, "license" includes the whole or a part of a Commission permit, certificate, approval, registration, or similar form of permission required by law.

(2) When an interim ruling suspends a license because an imminent peril to the public health, safety, or welfare requires emergency action, the examiner or Hearings Director shall incorporate a factual and legal basis establishing that imminent peril in the interim ruling.

(3) Unless expressly provided otherwise by statute, the Commission shall initiate the proceedings for revocation of the license or other action not later than the 30th day after the interim ruling is signed.

(d) Appeal of interim ruling.

(1) Except as provided in paragraph (2) of this subsection, any party aggrieved by an interim ruling may appeal that ruling to the Commission and seek a stay if the party files a written appeal within 10 days of the date the interim ruling is signed or stated in the record. Untimely appeals shall not be forwarded by examiners to the Commissioners, pursuant to subsection (e) of this section. If, by the 46th day after the date the interim ruling is signed or stated in the record, the Commission has not signed a written order ruling on the appeal, then the appeal shall be deemed denied and any granted stay is lifted.

(2) In all gas utility proceedings brought or conducted under Texas Utilities Code, Chapters 102, 103, 104, and 121, any party aggrieved by an interim ruling may appeal that ruling to the Commission and seek a stay if the party files a written appeal within five days of the date the interim ruling is signed or stated in the record. Untimely appeals shall not be forwarded by examiners to the Commissioners, pursuant to subsection (e) of this section. If, by the 20th day after the date the interim ruling is signed or stated in the record, the Commission has not signed a written order ruling on the appeal, then the appeal shall be deemed denied and any granted stay is lifted.

(3) In all proceedings, the appealing party shall serve the appeal in accordance with §1.45 of this title (relating to Service in Protested Contested Cases) on the same day the appeal is filed with the Docket Services Section.

(4) Any response to an appeal must be filed with the Docket Services Section and served in accordance with §1.45 of this title within 10 days of the date the appeal of the interim ruling was filed.

(5) Pending action on the appeal of the interim ruling, the Hearings Director or the examiner may issue a stay of the interim ruling.

(e) Procedure on appeal. The Commissioners may consider and rule on an appeal on or after the day following the day the response to the appeal is due. An order on an

appeal from an interim ruling shall not be subject to motions for rehearing pending issuance of the proposal for decision and signing of the final order. Any issue in an appeal that has been deemed denied by operation of law may be raised again in exceptions to the proposal for decision. When a timely appeal is filed under this section, the examiner shall:

(1) forward to each Commissioner a copy of the appeal along with a cover memorandum showing the date the appeal was filed, the date replies are due, and the date on which the appeal will be deemed denied if no Commission action is taken;

(2) forward to each Commissioner a copy of all replies to appeals of interim rulings which may be filed, and of any stay of the interim ruling granted by the Hearings Director; and

(3) upon the request of any one Commissioner, immediately schedule the appeal for consideration by the Commission at an open meeting, and cause proper notice to be given to all parties.

Source Note: The provisions of this §1.38 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER D NOTICE AND SERVICE

§1.41 Notice of Application in Contested Cases

Notice of application for contested cases shall be given in accordance with applicable law, rule, or order of the Commission.

Source Note: The provisions of this §1.41 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.42 Notice of Hearing

(a) In a contested case, each party is entitled to an opportunity:

(1) for hearing after reasonable notice of not less than 10 days; and

(2) to respond and to present evidence and argument on each issue involved in the case.

(b) Each notice of hearing shall include the following:

(1) a statement of the time, place, and nature of the hearing;

(2) a statement of the legal authority and jurisdiction under which the hearing is to be held;

(3) a reference to the particular sections of the statutes and rules involved;

(4) either a short, plain statement of the factual matters asserted or an attachment that incorporates by reference the factual matters asserted in the complaint or petition; and

(5) any other statements required by law or directed by the Commission.

(c) If the Commission or a party is unable to state the factual matters in detail at the time the notice is served, the initial notice may be limited to a statement of the issues involved. On timely written application, a more definite and detailed statement of the facts shall be submitted in writing to the Hearings Division, which shall issue an amended notice not less than seven days prior to the date set for the hearing.

(d) In a proceeding in which the Commission has the burden of proof, if the Commission intends to rely on a section of a statute or rule not previously referenced in the notice of hearing, the Hearings Division shall amend the notice to refer to the section of the statute or rule not less than seven days before the date set for the hearing. This subsection does not prohibit the Commission from filing an amended notice of hearing after the hearing has commenced. If the Commission files an amended notice of hearing after the hearing has commenced, the examiner shall grant a continuance of at least seven days at the request of any other party.

Source Note: The provisions of this §1.42 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.43 Notice by Publication

(a) When an applicant in a proceeding is unable, after due diligence, to identify the address of any person who is required to be notified of an application, complaint, or hearing, the applicant must publish notice of the application, complaint, or hearing.

(1) Unless otherwise directed by the appropriate director or examiner, the applicant shall publish the Commission's notice of application or notice of hearing in a newspaper of general circulation in the county or counties where the land or facility that is the subject of the application or hearing is located. The applicant shall publish such notice once per week for four consecutive weeks. The first publication shall be published at least 28 days before the protest deadline in a notice of application or the hearing date in a notice of hearing.

(2) The applicant must file proof of publication in the form of a publisher's affidavit or present at a hearing a copy of the newspaper notice along with testimony by a person with personal knowledge of the publication details.

(b) In determining whether notice by publication is appropriate, the examiner may consider whether an applicant used due diligence in attempting to identify the address of any person who is required to be notified of an application, complaint, or hearing.

Source Note: The provisions of this §1.43 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.44 Notice of Protest

A notice of protest may be filed when the notice of application, notice of hearing, or a Commission rule sets forth the requirements for filing such notice, or as provided by order of the Commission instituting the proceeding.

Source Note: The provisions of this §1.44 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.45 Service in Protested Contested Cases

(a) Service requirements. A copy of any pleading or document filed in a protested contested case shall be served by a party as follows:

(1) On the same day a party files a document with the Commission, the party shall serve a copy on every other party and any other person required by the Hearings Division. If a party is represented by an authorized representative, service shall be made on that representative; and

(2) All filings shall include a certificate of service that copies have been served on all persons described in paragraph (1) of this subsection. The certificate of service shall include the date and manner of service and the names and addresses of all persons served. If a person is served by fax or email, the certificate of service shall include the person's fax number or email, as applicable.

(b) Methods of service.

(1) A pleading or document may be served by hand delivering a copy to the person to be served, or by first class,

certified, or registered mail, commercial delivery service, fax, email, or by such other manner as the Commission may require.

(A) Service by mail or commercial delivery service shall be complete upon deposit of the document postpaid and properly addressed to the person's last known address with the United States Postal Service or a commercial delivery service.

(B) Service by fax shall be sent to the person's current fax number and is complete on the date of the fax. Fax transmissions completed after 5 p.m. local time of the recipient shall be deemed served on the following business day.

(C) Personal service may be effectuated by hand delivering a copy to the person to be served and is complete on the date of delivery. Personal service completed after 5 p.m. local time of the recipient shall be deemed served on the following business day.

(D) Service by email may be used if the person to be served consents to be served by email pursuant to §1.27 or §1.32 of this title (relating to Parties and Authorized Representatives, and Form and Content of Pleadings, respectively). If the person consents to be served by email, the person affirmatively consents to the release and disclosure of the email address. Email service is complete on the date of the email transmission. An email received after 5 p.m. local time of the recipient shall be deemed served on the following business day.

(2) Proof of service. The filing party or authorized representative shall certify compliance with this rule in writing over signature and on the filed instrument. A certificate showing service shall be prima facie evidence of the fact of service. In cases of personal service, the certificate shall state when the pleading or motion was served and the manner of service. The recitations in the certificate are prima facie evidence of the facts cited in the certificate.

(c) Service by mail or commercial delivery service. Unless otherwise directed by the examiner or Hearings Director, when a party is required to do some act within a prescribed time period following service of a pleading, motion, or discovery document described in §1.51 of this title (relating to Forms and Scope of Discovery in Contested Cases) and the pleading, motion, or discovery document is served by mail or commercial delivery service, three days shall be added to the prescribed response period.

(d) Failure to serve. The serving party has the burden of proving the date and time of service. The failure of a party to serve a pleading or filed document on another party or person as required by this section may be sufficient grounds for the Hearings Director or the examiner to strike the pleading or filed document, or to take other appropriate action. A party may offer evidence or testimony that a notice or document was not received, or if service was by mail, that it was not received within three days from the date of mailing, and upon so finding, the examiner or Hearings Director may extend the time for taking the action required of the party or grant other appropriate relief.

(e) Service by the Commission.

(1) For documents served on a party with an active or delinquent organization report on file pursuant to §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements), the Commission shall serve documents by:

(A) first class mail to the address shown on the most recently filed organization report or the most recently filed letter notification of change of address, in which case the document is presumed received if the document is not returned to the Commission;

(B) certified mail to the address described in subparagraph (A) of this paragraph, in which case service is effective upon:

(i) acceptance of the item by any person at the address;

(ii) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the Commission by the United States Postal Service; or

(iii) return of the item to the Commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect; or

(C) personal service or registered or certified mail to the address described in subparagraph (A) of this paragraph for revocation, suspension, annulment, or withdrawal of a license.

(2) For documents served on all other parties, unless otherwise required by law, the Commission shall serve documents in accordance with subsection (b) of this section.

Source Note: The provisions of this §1.45 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER E DISCOVERY

§1.51 Forms and Scope of Discovery in Protested Contested Cases

(a) Permissible forms of discovery by parties are:

(1) oral depositions of a party or a nonparty;

(2) written interrogatories to a party;

(3) requests to a party for admission of facts or the genuineness or identity of documents or things;

(4) requests to a party for production, examination, and copying of documents or other tangible materials;

(5) requests to a party for entry upon and examination of real or personal property, or both; and

(6) requests to a party for disclosures pursuant to Texas Rule of Civil Procedure 194.

(b) The scope of discovery shall be the same as provided by the Texas Rules of Civil Procedure and shall be subject to the constraints provided therein for privileges, objections, protective orders, and duty to supplement as well as the constraints provided in the APA.

Source Note: The provisions of this §1.51 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.52 Discovery Requests and Responses

(a) Requests for discovery and responses shall be served using a method of service authorized by §1.45 of this title (relating to Service in Protested Contested Cases) and should not be filed with the Commission.

(b) Except for good cause shown, all requests for discovery shall be served at least 20 days prior to the hearing unless otherwise agreed by the parties.

(c) Responses to discovery requests shall be served within 14 days after the date of service of the request. The examiner or the Hearings Director may alter this deadline on the request of any party.

Source Note: The provisions of this §1.52 adopted to be

effective August 21, 2017, 42 TexReg 4131

§1.53 Request for Deposition

(a) If the parties disagree on the scheduling or scope of a deposition, a deposition request and proposed deposition discovery order shall be filed with the Docket Services Section and the examiner will set the matter for consideration at a prehearing conference.

(b) The deposition shall be returned to the Commission as provided in the APA, §2001.100.

Source Note: The provisions of this §1.53 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.54 Requests for Admission

Except as otherwise provided in §1.53 of this title (relating to Deadlines for Responses to Discovery Requests), requests for admission shall be governed by the applicable provisions of the Texas Rules of Civil Procedure. Each matter for which an admission is requested shall be separately stated. If a written answer or objection to a request for admission is not timely served, the request is deemed admitted without necessity of a Commission order. The requests for admission document must clearly set forth this provision for deemed admissions, in bold print or by underlining, in a conspicuous location to fairly inform the responding party of the consequences of a failure to respond within the prescribed time period. The examiner may permit withdrawal or amendment of responses and deemed admissions upon a showing of good cause.

Source Note: The provisions of this §1.54 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.55 Discovery Orders

(a) Discovery orders generally. The Hearings director or the examiner may issue protective orders, orders compelling discovery responses, and orders creating a discovery control plan. Requests for discovery orders shall contain a sworn statement that, after due diligence, the desired information cannot be obtained through informal means, and that good cause exists for requiring discovery. The request for a discovery order may be denied:

(1) if the request is untimely or unduly burdensome in light of the complexity of the proceeding;

(2) if the requesting party has failed to exercise due diligence;

(3) if the discovery would result in undue cost to the parties or unnecessary delay in the proceeding; or

(4) for other good cause in the interest of justice.

(b) Motion to compel. Unless otherwise ordered, a party alleging another party's failure to comply with discovery requests shall file a sworn motion to compel with the Docket Services Section at least 10 days prior to the hearing on the merits.

(c) Deposition discovery orders. The Hearings Director or the examiner is authorized to issue a subpoena to take a deposition, which shall require that the witness appear and produce, at the time the deposition is taken, books, records, papers, or other objects that may be necessary and proper for the purposes of the proceeding.

(d) In camera inspection. The Hearings Director or the examiner may conduct in camera inspections of materials when requested by a party or when necessary to determine facts required to issue appropriate discovery orders.

(e) Review by Commissioners. Any discovery order issued by the examiner or the Hearings Director is subject to review by an appeal to the Commissioners. Any party that chooses to appeal a discovery order shall follow the requirements set forth in §1.38 of this title (relating to Interim Rulings and Appeals of Interim Rulings). A discovery order does not constitute a final order or decision.

(f) Compliance. The Commission may enforce compliance with any discovery order or subpoena pursuant to Texas Government Code §§2001.089, 2001.094, and 2001.201, and the Texas Natural Resources Code, §81.053 and §81.064, or as otherwise permitted by law.

Source Note: The provisions of this §1.55 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.56 Alignment of Municipal Intervenors for Purposes of Discovery

(a) This section applies to proceedings initiated pursuant to Texas Utilities Code, §103.055 and §104.102.

(b) Municipal intervenors, whether participating as a single municipality or a coalition of municipalities, are presumed to share a common interest in a proceeding such that alignment of municipal intervenors as a single party for purposes of discovery is appropriate. The examiner shall order alignment of municipal intervenors at the earliest reasonable opportunity so as to avoid unnecessary duplication of effort and to allow aligned parties an adequate opportunity to coordinate discovery efforts in an efficient manner.

(c) To overcome the presumption of alignment, a municipality or municipal coalition must file a motion to realign in whole or in part. In ruling on such a motion, the presiding officer shall consider whether good cause exists to grant the motion to realign in whole or in part including consideration of the following:

(1) whether the municipal intervenors are taking opposing positions regarding the utility's request for relief;

(2) whether the municipal intervenors have sufficiently different positions on one or more issues to justify realignment on such issues;

(3) whether granting the motion will create unnecessary inefficiencies or duplication of effort;

(4) whether granting the motion will result in undue costs to the parties;

(5) the effect of granting the motion on the parties and the public interest;

(6) whether granting the motion will serve the interest of justice; and

(7) any other relevant factors as determined by the presiding officer.

Source Note: The provisions of this §1.56 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.57 Limitations on Discovery Requests

(a) This section applies to proceedings brought pursuant to Texas Utilities Code, §103.055 and §104.102.

(b) Upon request by a party, the presiding officer may limit discovery, by order, in the interest of efficiency and justice.

(c) For purposes of calculating the number of requests for information (RFIs), each request or subpart shall be considered a separate RFI. Absent a showing of good cause, a reasonable limitation on RFIs propounded to a party is no more than 600 total RFIs, with no more than 75 RFIs propounded by a single party in one calendar week. Commission staff and presiding officers are not subject to these discovery limitations when Commission staff or the

presiding officers issue the RFIs.

(d) With regard to discovery propounded by a municipality or municipal coalition, to the extent that the utility first filed its request for relief at the municipal level and a municipal party has requested that the discovery propounded at the municipal level be updated, and the Commission is now considering the utility's request on appeal from the municipal forum, the number of RFIs (inclusive of subparts) that the municipality propounded at the municipal level shall count towards the total number of permissible RFIs a municipality may serve on the utility during the Commission proceeding on appeal, unless the utility updated its test year when filing its appeal.

(e) If a party is not required to answer a question due to a sustained objection or withdrawal, that question may not be included in the calculation of the propounding party's RFI limit. However, if the presiding officer determines that a party is intentionally propounding frivolous, irrelevant, or otherwise objectionable requests, the question shall be included in the calculation of that propounding party's RFI limit.

(f) As set forth in the Texas Rules of Civil Procedure 196 and 198, there shall be no limitation with regard to requests for production and inspection, or requests for admission.

(g) The party propounding discovery shall separately characterize its discovery as an RFI, a Request for Production and Inspection, or a Request for Admission.

Source Note: The provisions of this §1.57 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER F EVIDENCE

§1.61 Rules of Evidence

The Texas rules of evidence and Texas law with regard to evidence in nonjury civil cases shall apply in contested cases unless Commission rules specify otherwise. Irrelevant, immaterial, or unduly repetitious evidence may be excluded. When necessary to ascertain facts not reasonably susceptible of proof under those rules, evidence not admissible thereunder may nevertheless be admitted by the examiner (except where precluded by statute) if it is of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs. The rules of privilege recognized by law shall apply in Commission proceedings. Objections to evidentiary offers may be made and shall be noted in the record.

Source Note: The provisions of this §1.61 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.62 Official Notice

(a) Facts noticeable. Official notice may be taken of judicially cognizable facts, and notice may be taken of generally recognized facts within the area of the Commission's specialized knowledge.

(b) Motions for official notice and opportunity to respond. A party's motion for official notice must be made or filed prior to the conclusion of the evidentiary hearing. The motion must specify the facts, material, records, or documents encompassed in the motion. A party who opposes the motion shall have the opportunity to contest the requested action.

(c) Notification of materials noticed. The examiner on his or her own motion, or the Commission on its own motion, may propose to take official notice of facts, material, records, or documents authorized by the APA, §2001.090. The parties will be given the opportunity to contest the proposed action and shall be notified of the facts, material, records, or documents officially noticed before, during, or after the hearing by the Commission.

Source Note: The provisions of this §1.62 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.63 Documentary Evidence

A copy or excerpt of a document may be admitted as evidence if the original is not readily available and if authenticity is established by competent evidence. When numerous or duplicative documents are offered, the examiner may limit those admitted to a number of documents which are typical and representative. The examiner may require the offering party to abstract or summarize relevant data from documents and present the abstracts or summaries in exhibit form. All parties shall have the right to examine the documents abstracted or summarized.

Source Note: The provisions of this §1.63 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.64 Written Testimony

(a) Admissibility. When a proceeding will be expedited and the interests of the parties will not be substantially prejudiced, direct testimony may be offered in written form. The written testimony of a witness on direct examination, either in narrative or question and answer form, may be offered as an exhibit and incorporated into the record without the written testimony being read. A witness who is offering written testimony shall be sworn and shall identify the written testimony as a true and accurate representation of what the testimony would be if the witness were to testify orally, after which the witness shall submit to voir dire and cross-examination. Written testimony shall be subject to the same evidentiary objections as oral testimony.

(b) Prefiling. The Commission, the Hearings Director, or an examiner may require or permit written testimony and exhibits to be filed and served on all parties at a specified date prior to the hearing. Failure to prefile written testimony and exhibits if required under this section shall be sufficient cause for the examiner to rule such evidence, which was to be included in the testimony and exhibits, inadmissible or for other appropriate action to be taken as may be just and reasonable.

Source Note: The provisions of this §1.64 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.65 Exhibits

(a) Form. Exhibits to be offered in evidence at a hearing shall be of a size which will not unduly encumber the record. Whenever practicable, exhibits shall conform to the size requirements established by §1.32 of this title (relating to Form and Content of Pleadings). The pages of each exhibit shall be numbered consecutively.

(b) Tender and service. The original or a true and correct copy of each exhibit offered in evidence shall be identified and tendered for inclusion in the record. Copies of the exhibit shall be furnished to the examiners, to the court reporter, and to each party prior to or at the time the exhibit is offered in evidence.

(c) Excluded exhibits. If an exhibit is offered, objected to, and excluded, the examiner may determine whether or not the party offering the exhibit wishes to withdraw the offer; if so, the examiner shall permit the return of the exhibit to the

party. If the excluded exhibit is not withdrawn, it shall be given an exhibit number for identification, shall be endorsed by the examiner with the ruling, and shall be included in the record for the purpose of preserving an exception.

(d) Late exhibits. Unless specifically requested and permitted by the Commissioners, the Hearings Director, or the examiner, no exhibit shall be filed in any proceeding after the hearing has been completed. If the filing of a late-filed exhibit is permitted, copies shall be served on all parties, and each party will have the opportunity to respond and submit additional relevant responsive evidence.

Source Note: The provisions of this §1.65 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.66 Written Objections Not Required

Written objections to rulings made by the examiner during a hearing are not required. It shall be sufficient that the party make a timely objection and state the grounds for the objection on the record.

Source Note: The provisions of this §1.66 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.67 Offers of Proof

(a) When the examiner excludes evidence, the party offering the evidence shall be permitted to make an offer of proof prior to the close of the hearing.

(1) The party may make the offer in question and answer form, or by dictating or submitting in writing the substance of the proposed evidence.

(2) The examiner may direct the manner in which the offer is made and may ask questions if necessary to conclude that the evidence would be as represented.

(3) The examiner and opposing parties shall be entitled to cross-examine any witness testifying on an offer of proof.

(b) The examiner may direct that offers of proof be transcribed separately and that reporter's costs be assessed against the proponent of the evidence, subject to the Commissioners' review of the examiner's ruling.

Source Note: The provisions of this §1.67 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.68 Confidential Materials

(a) Applicability of the Public Information Act. All records, data, and information filed with the Commission are subject to the Texas Public Information Act, Texas Government Code, Chapter 552. If the Commission receives a third party request for materials that have been marked confidential pursuant to subsection (b) or (c) of this section, the Commission will notify the filing party of the request in accordance with the provisions of the Texas Public Information Act so that the party can take action with the Office of the Attorney General to oppose release of the materials.

(b) Filing confidential materials in a hearing before the Hearings Division.

(1) A party filing material in a hearing before the Hearings Division that the party contends to be confidential by law shall file the materials with the Docket Services Section by delivering them in a sealed and labeled container, accompanied by an explanatory cover letter. The cover letter shall identify the docket number and the style of the case, explain the nature of the sealed materials, and specify the relief sought. The outside of the container shall identify the docket number, the style of the case, the name of the submitting party, and be marked "CONFIDENTIAL AND UNDER SEAL" in bold print at least one inch in size. The front page of each portion of confidential material shall be marked "confidential." Confidential material shall not be filed by fax. A party who elects to file confidential material electronically shall notify the Docket Services Section prior to filing such material.

(2) A party may file a motion to seal the record if it has filed confidential materials in accordance with paragraph (1) of this subsection. In the motion, the party shall describe the materials it contends to be confidential by law, indicate the specific provision of law that exempts the material from disclosure, and request that the examiner order the described materials to be sealed. The examiner may, after consideration at hearing, order the described materials to be sealed, subject to any determination by the Office of the Attorney General and as further described in subsection (a) of this section.

(3) Confidential materials filed with the Hearings Division will be retained until the contested case is no longer appealable and in accordance with the Commission's retention policy.

(c) Filing confidential materials with the Commission other than in a hearing.

(1) A party filing material with a division of the Commission other than the Hearings Division that the party contends to be confidential by law shall file the materials with the applicable division by delivering them in a sealed and labeled container accompanied by an explanatory cover letter. The cover letter shall explain the nature of the sealed materials. The outside of the container shall identify the name of the submitting party and be marked "CONFIDENTIAL AND UNDER SEAL" in bold print at least one inch in size. The front page of each portion of confidential material shall be marked "confidential." Confidential material shall not be filed by fax. A party who elects to file confidential material electronically shall notify the applicable division prior to filing such material.

(2) Confidential materials filed under this subsection will be retained in accordance with the Commission's retention policy.

Source Note: The provisions of this §1.68 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER G HEARINGS

§1.101 Examiner's Powers and Duties

(a) For any assigned case and subject to any limitations imposed by law or by Commission rule, the examiner shall have broad discretion in regulating the course and conduct of the hearing. The examiner's authority includes, but is not limited to, the following authority:

(1) to administer oaths and affirmations;

(2) to issue subpoenas to compel the attendance of witnesses and the production of papers and documents;

(3) to authorize the taking of depositions and issue discovery orders;

(4) to call and examine witnesses;

(5) to receive evidence;

(6) to rule upon the admissibility of evidence and amendments to pleadings;

(7) to limit the number of witnesses whose testimony would be merely cumulative;

(8) to set reasonable times within which a party may testify, cross-examine witnesses, or present evidence;

(9) to impose sanctions;

(10) to maintain order in a hearing;

(11) to recess any hearing;

(12) to issue a proposal for decision, including proposed findings of fact and conclusions of law and a recommended order;

(13) to reopen the record when justice requires;

(14) to amend the proposal for decision or recommended order, or both;

(15) to issue a supplemental or amended proposal for decision and proposed order;

(16) to review the jurisdiction of the Commission and standing of parties as it pertains to a contested case;

(17) to issue orders relating to hearing, prehearing and posthearing matters; and

(18) to take other permissive action which is necessary for a fair, just, and proper hearing.

(b) If at any time the examiner is unable to continue to serve, the Hearings Director may appoint another examiner to perform any remaining functions without the necessity of repeating previous proceedings.

(c) At their discretion, the Commissioners may preside over contested cases pursuant to this section.

Source Note: The provisions of this §1.101 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.102 Sanctioning Authority

(a) In the interest of justice, and after notice and opportunity for hearing, an order imposing sanctions may be issued by the Commissioners, the Hearings Director, or the examiner for:

(1) abuse of the discovery process, including failure to comply with a discovery order or subpoena issued by the Commission for deposition or production of books, records, papers, or other objects;

(2) filing a motion or pleading that is determined to be groundless and brought:

(A) in bad faith;

(B) for the purpose of harassment; or

(C) for any other improper purpose, such as to cause unnecessary delay or increase in the cost of the proceeding; or

(3) failure to obey an order of the Commissioners, the Hearings Director, or the examiner.

(b) The order imposing sanctions may:

(1) disallow any further discovery of any kind or of a particular kind by the sanctioned party;

(2) require the party, the party's authorized representative, or both to obey the discovery order;

(3) require the party, the party's authorized representative, or both to pay reasonable expenses, including attorney fees, incurred by reason of the party's noncompliance;

(4) direct that the matters for which the discovery order was made shall be deemed admitted in accordance with the claim of the party obtaining the order;

(5) refuse to allow the sanctioned party to support or oppose designated claims or defenses or prohibit the party from introducing designated matters in evidence;

(6) strike pleadings or parts thereof or abate further proceedings until the order is obeyed;

(7) disallow in whole or in part requests for relief by the offending party and exclude evidence in support of those requests; or

(8) dismiss the action or proceeding or any part thereof or render a decision by default against the sanctioned party.

(c) Any order imposing sanctions issued by the examiner or the Hearings Director is subject to review by an appeal to the Commissioners. The appeal shall be filed with the Docket Services Section, which will forward the pleading to the Commissioners and the Hearings Director.

Source Note: The provisions of this §1.102 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.103 Prehearing and Posthearing Conferences

(a) The Hearings Director or examiner may direct the parties, the parties' authorized representatives, or both, to appear at a prehearing or posthearing conference to consider the following, as may be applicable:

(1) motions and other preliminary matters relating to the proceeding, including discovery;

(2) settlement of the case or simplification of the issues;

(3) amendment of pleadings;

(4) admissions or stipulations which will avoid the unnecessary introduction of evidence;

(5) limitations on the number of witnesses;

(6) time to be allotted to each party for presentation of its direct case or for cross-examination at the hearing;

(7) procedures to be followed at the hearing; and

(8) other matters that may aid in the disposition of the proceeding.

(b) For any ruling not disclosed on the record, the examiner shall notify the parties in writing of the disposition of a matter considered at a prehearing or posthearing conference.

Source Note: The provisions of this §1.103 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.104 Stipulations

The examiners will not consider any stipulation or agreement unless it is in writing and signed by the parties or their authorized representatives, or dictated into the record during the course of the proceeding. This section does not limit a party's ability to waive or modify by stipulation any right or privilege afforded by these rules, unless otherwise precluded by law.

Source Note: The provisions of this §1.104 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.105 Continuances

(a) A motion for continuance shall:

(1) be in writing and served in accordance with §1.45 of this title (relating to Service in Protested Contested Cases;

(2) be filed not less than five business days prior to the hearing, except for good cause shown;

(3) set forth the specific grounds for which the moving party seeks continuance;

(4) make reference to all similar motions filed in the proceeding; and

(5) state whether all parties agree with the relief requested.

(b) A continuance will not be granted based on the need for discovery if discovery requests have not previously been served upon the person from whom discovery is sought, except when necessary due to surprise or discovery of facts or evidence previously undisclosed despite the diligence of the moving party.

(c) The moving party shall confer with all other parties

regarding the motion and establish mutually agreeable calendar dates on which the parties are available.

(d) A motion for continuance shall be acted upon by the examiner or Hearings Director, subject to Commission review.

(e) If the motion is filed less than five business days prior to the hearing, the moving party shall state good cause for the failure to timely file and immediately notify all parties and the assigned court reporter of the disposition of the motion.

Source Note: The provisions of this §1.105 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.106 Consolidation and Joint Hearings

When two or more applications, petitions, or other proceedings involve common questions of law or fact, the appropriate division director, the Hearings Director or the examiner may consolidate the proceedings or direct that there be a joint hearing without formal consolidation and may take other action to avoid unnecessary costs or delay and to ensure due process.

Source Note: The provisions of this §1.106 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.107 Dismissal

The Commissioners or the Hearings Director may dismiss, with or without prejudice, any proceeding under such conditions and for such reasons as are found to be just and reasonable, including the following:

(1) failure to prosecute;

(2) unnecessary duplication of proceedings or res judicata;

(3) withdrawal;

(4) moot questions or obsolete petitions;

(5) lack of jurisdiction; or

(6) if necessary in the interest of justice.

Source Note: The provisions of this §1.107 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.108 Place and Nature of Hearings

All hearings shall be open to the public and, except as otherwise required by law, shall be held in Austin. The Commissioners or the Hearings Director may designate another place of hearing if for good cause and in the public interest.

Source Note: The provisions of this §1.108 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.109 Hearing Procedures

(a) Opening the hearing. The examiner shall call the hearing to order and make a concise statement of its scope and purposes. All parties shall then enter their appearances. Thereafter, parties may make motions or opening statements.

(b) Order of procedure. Parties shall be permitted to make opening statements, offer direct evidence, cross-examine witnesses, and present supporting arguments. The party having the burden of proof shall be entitled to open and close. When several proceedings are heard on a consolidated record or when the proceeding has been initiated by the Commission, the examiner shall designate who may open and close. The examiner shall determine at what stage intervenors will be permitted to offer evidence. The examiner may direct that closing arguments be made in writing. The examiner may alter the order of procedure if necessary for efficient conduct of the hearing.

(c) Voir dire. Voir dire examination to evaluate the qualifications of a witness to testify may be permitted but will not be substituted for cross-examination.

(d) Rebuttal. The petitioner, applicant, or complainant may rebut evidence and argument presented by protestants or intervenors. The examiner may allow additional rebuttal from other parties.

(e) Additional evidence. The Commissioners, Hearings Director, or examiner may subpoena records or may call upon or subpoena for additional evidence on any issue any party, person, or employee of the Commission who is not assigned to render a decision or to make findings of fact and conclusions of law for additional evidence on any issue. Additional evidence shall not be admitted without an opportunity for examination, objection, and rebuttal by all parties.

Source Note: The provisions of this §1.109 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.110 Burden of Proof

Generally, the party seeking affirmative relief shall have the burden of proof. An examiner may reassign the burden of proof and shall serve copies of the decision on all parties. In reassigning the burden of proof, the examiner may consider:

(1) the classification of the parties;

(2) the parties' access to information pertinent to the merits of the case;

(3) the party seeking affirmative relief;

(4) the party seeking to change the status quo;

(5) whether a party would be required to prove a negative; and

(6) the nature of the relief that is requested.

Source Note: The provisions of this §1.110 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.111 Reporters and Transcripts

(a) Request for transcript. When requested by the Commission, the examiner, or a party, a certified shorthand reporter shall make a verbatim record and transcript of the hearing.

(b) Assessment of costs. The cost of the original transcripts shall be assessed to all parties equally unless otherwise directed by the examiner or required by law.

(c) Charges. The Commission shall approve rates to be charged by reporters for appearances, original transcripts, and copies. The rates shall not exceed rates authorized by law to be paid to court reporters in Texas district courts.

Source Note: The provisions of this §1.111 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.112 Proceedings by Telephony

(a) The examiner may sua sponte or upon granting the timely written motion of a party order that all or part of a prehearing or posthearing conference or hearing be conducted by telephony.

(b) A party may file a motion to appear at a prehearing or posthearing conference or a hearing by telephony as follows:

(1) The motion shall be in writing, shall be filed with the Docket Services Section and served in accordance with §1.45 of this title (relating to Service in Protested Contested Cases) not less than 10 days prior to the proceeding at which the party wishes to appear remotely, and shall include the pertinent telephone number(s) and/or other connection instructions.

(2) If the motion is to conduct only a portion of the proceeding by telephony, the requesting party shall identify the relevant portion of the proceeding to be conducted by telephony.

(3) Any reply to a motion shall be made in writing and shall be filed with the Docket Services Section and served in accordance with §1.45 of this title within five days of service of the motion.

(4) Upon agreement of the parties or a finding of good cause, the examiner may modify the times for filing a motion for an appearance by telephony and/or replies to such a motion.

(c) Unless a timely objection is filed by another party, the examiner may grant the motion if:

(1) the moving party will not present any evidence as part of its direct case other than the oral testimony of that party or a single party representative; and

(2) the motion is to appear by telephony for which the Commission has all necessary equipment and technology.

(d) If a timely objection is filed, the objecting party has the burden of showing how the requested relief will unduly burden the proceeding or unfairly prejudice the objecting party.

(e) If the moving party will present any evidence other than the oral testimony of that party or a single party representative or requests a method of telephony for which the Commission does not have all necessary equipment and technology, and no timely objection is filed, the examiner shall consider the factors in subsection (f) of this section and issue a ruling on the motion. If a timely objection is filed, the moving party shall have the burden of showing that the requested relief will not unduly burden the proceeding or unfairly prejudice any party and the examiner shall issue a ruling taking into consideration the arguments of the parties and the factors in subsection (f) of this section.

(f) In considering whether conducting all or part of a prehearing or posthearing conference or hearing by telephony is feasible, the examiner shall ensure that the proceeding will provide due process and will be fair, and shall take into account the following factors:

(1) whether a party's request is timely;

(2) whether all parties to a protested proceeding have agreed in writing to conducting all or part of the proceeding by telephony;

(3) equipment and technology constraints;

(4) the number of parties;

(5) the number of witnesses;

(6) the number and type of exhibits;

(7) the distance of the parties or witnesses from Austin;

(8) the nature of the hearing;

(9) the testimony to be offered; and

(10) any other pertinent factors which may affect the proceeding.

(g) The examiner shall issue a ruling within a reasonable time period prior to the proceeding stating whether the proceeding will be conducted, in whole or in part, by telephony and serve prompt written notice of the ruling on all parties.

(h) The Commission may consider the following events to constitute a failure to appear and grounds for default or dismissal:

(1) failure to connect or answer for more than 10 minutes after the scheduled time for the proceeding;

(2) failure to be ready to proceed with the proceeding after 10 minutes of the scheduled time; and

(3) a party's intentional disconnection.

(i) In the event of accidental disconnection of one or more parties to the proceeding or other technical issues, the examiner shall immediately recess the hearing and attempt to re-establish the connection or connections.

Source Note: The provisions of this §1.112 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER H DECISION

§1.121 Proposals for Decision

(a) In a contested case, if a majority of the Commissioners have not heard the case or read the record, the decision, if adverse to a party other than the Commission, may not be made until:

(1) a proposal for decision is served on each party; and

(2) an opportunity is afforded to each adversely affected party to file exceptions and present briefs to the Commission.

(b) The proposal for decision must contain a statement of the reasons for the proposed decision and of each finding of fact and conclusion of law necessary to the proposed decision, prepared by the person who conducted the hearing or by one who has read the record.

(c) The parties may waive the requirements of subsections (a) and/or (b) of this section by written stipulation.

(d) The examiner may direct a party to draft and submit proposed findings of fact and conclusions of law. The examiner may limit the request for proposed findings or conclusions to any particular issue or issues of fact. The party's proposed findings of fact and conclusions of law shall be supported by concise and explicit statements of underlying facts developed from the record with specific record references. If the examiner requires the filing of proposed findings of fact or conclusions of law, the Commissioners shall rule on each proposed finding and conclusion. If the examiner permits but does not require a party to submit proposed findings of fact or conclusions of law, a ruling on the proposed findings or conclusions is not required.

(e) When a proposal for decision is issued, a copy of the proposal shall be served promptly on each party or its authorized representative.

(f) An examiner may amend or correct a previously served proposal for decision or proposed order and shall serve the amendment or correction on the parties. Exceptions and replies are not permitted in response to a clerical or typographical correction. When substantive amendments are necessary prior to presentation at conference, an examiner shall specify the time period for the filing of exceptions and replies. Amendments adopted by the Commission shall be noted with specificity in the Commission's final order.

Source Note: The provisions of this §1.121 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.122 Filing of Exceptions and Replies

(a) Any party may, within 15 days after the date of service of a proposal for decision, file exceptions to the proposal for decision. Replies to such exceptions may be filed by any other party within 10 days after the deadline for filing such exceptions. Either party may file a case summary with the party's exceptions or replies.

(1) Exceptions and replies shall be filed with the Docket Services Section by hand delivery, first class, certified or registered mail, or commercial delivery service. The number of copies filed will be determined by the examiner as stated in the notice to the parties issued with the proposal for decision. Exceptions, replies, and case summaries may not be filed by fax or email unless permitted by the examiner or Hearings director.

(2) All copies shall be unstapled and three-hole punched for a three-ring binder.

(3) The filing party shall serve the exceptions or replies in accordance with §1.45 of this title (relating to Service in Protested Contested Cases).

(b) The examiner, or the parties by agreement with the examiner's approval, may lengthen or shorten the time periods set out in this section if good cause is shown. A request for extension of time within which to file exceptions or replies shall be filed with the examiner and copies shall be served by the party making such a request in accordance with §1.45 of this title. The examiner shall promptly notify the parties of any action taken and shall grant the request only if good cause is shown.

(c) The Commissioners may consider the case as soon as:

(1) the time for filing exceptions and replies expires; or

(2) the exceptions and replies are filed, if filed before the filing deadline.

(d) Additional filings shall not be made and will not be accepted or considered after an item has been included on a Commission open meeting agenda posted with the Secretary of State unless the filing:

(1) exclusively concerns material circumstances or events that arose after the item was posted; or

(2) was requested by the Commissioners, the Hearings Director, or the examiner.

Source Note: The provisions of this §1.122 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.123 Commission Action

(a) At an open meeting, the Commissioners may:

(1) adopt, modify, or reject the examiner's proposed findings of fact and conclusions of law in whole or in part;

(2) remand the proceeding for further consideration by the same examiner or a different examiner;

(3) direct the examiner to further consider the case with or without reopening the hearing.

(b) If, on remand by the Commissioners, additional evidence is received which results in a substantial change of the examiner's recommendation for final action, an amended proposal for decision shall be prepared and circulated to the parties, unless a majority of the Commission has held the hearing or read the record. If an amended proposal for decision is prepared, all parties shall have the right to file exceptions, replies, and briefs.

Source Note: The provisions of this §1.123 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.124 Oral Argument before the Commission

(a) Any party may request oral argument on a matter before the Commissioners by filing the request with the Docket Services Section as part of a party's exceptions, replies to exceptions, motion for rehearing, or reply to a motion for rehearing. A party may not orally request the opportunity to make oral argument at a Commission open meeting.

(b) Oral argument may be allowed at the discretion of the Commissioners. Failure of the Commissioners to grant a request for oral argument shall be deemed denial of the request.

(c) The Commissioners may request that parties to any proceeding present oral argument.

(d) If the Commissioners will hear oral argument, the Commissioners shall determine the date, time, and order of the oral argument. The Commissioners may:

(1) request that parties focus their arguments on particular issues in the case;

(2) determine the sequence in which parties will proceed, and which party, if any, may close;

(3) impose time limits on all speakers;

(4) limit or exclude unduly repetitious arguments and presentations;

(5) require that one representative present the information and position of closely aligned persons or entities; and

(6) set deadlines for filing additional information or written briefs in the case.

(e) Persons who need special equipment or assistance and who have a special request concerning the presentation of comments or oral argument should contact the secretary of the Commission at least 48 hours prior to the start of the open meeting to ensure that they are provided with the necessary special equipment or assistance. Failure to make such a request will not preclude a person from providing comment or oral argument. A special request includes:

(1) presentation of video or audio recordings; and/or

(2) use of audio or visual aids.

(f) The Commissioners will accept unsolicited comments from elected officials when they are acting in their official capacities.

Source Note: The provisions of this §1.124 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.125 Interim Orders Entered by the Commissioners

When an interim order is provided for by law, a request for an interim order will be presented to the Commissioners for consideration at an open meeting. An interim order shall not be considered a final Commission decision. Interim orders are not appealable and shall not be subject to exceptions or motions for rehearing, as provided by the APA or the rules in this chapter.

Source Note: The provisions of this §1.125 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.126 Final Decisions and Orders

(a) A final decision or final order adverse to any party in a contested case shall be in writing and shall be signed by two or more Commissioners. Final decisions or final orders shall include findings of fact and conclusions of law separately stated. Findings of fact, if set forth in statutory language, shall be accompanied by a concise and explicit statement of the underlying facts supporting the findings. If in accordance with §1.121 of this title (relating to Proposals for Decision) a party submits proposed findings of fact or conclusions of law as required by the examiner, the decision shall include a ruling or order on each proposed finding. All parties shall be notified of any decision or order pursuant to subsections (b) and (c) of this section.

(b) When a decision or order in a contested case that may become final under Texas Government Code,

§2001.144 is signed or when an order ruling on a motion for rehearing is signed, the Commission shall deliver or send a copy of the decision or order to each party in accordance with subsection (c) of this section. The Commission shall keep a record documenting the provisions of the notice provided to each party.

(c) Methods of notice. The Commission shall notify each party to a contested case of any decision or order of the Commission using at least one of the following methods of service:

(1) personal service;

(2) if agreed to by the party to be notified, service by email to the party's current email address or fax number of the party's authorized representative, or of the party if the party is not represented;

(3) service by first class, certified, or registered mail, or commercial delivery service sent to the last known address of the party's authorized representative or of the party if the party is not represented; or

(4) service by a method required by a rule or order of the Commission.

Source Note: The provisions of this §1.126 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.127 Effective Date

A decision or order becomes final as provided in §1.130 of this title (relating to Finality of Decisions or Orders). The effective date of a decision or order is the date it is signed by a majority of the Commissioners, unless otherwise stated in the order and subject to a motion for rehearing. The effective date shall be incorporated into the body of the decision.

Source Note: The provisions of this §1.127 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.128 Motions for Rehearing

(a) Motions for rehearing, if filed, must be filed by a party not later than the 25th day after the decision or order that is the subject of the motion is signed, unless the time for filing the motion for rehearing has been extended under subsection (e) of this section. A motion for rehearing must identify with particularity the findings of facts or conclusions of law that are the subject of the complaint and any evidentiary or legal ruling claimed to be erroneous. The motion must also state the legal and factual basis for the claimed error. On filing of the motion for rehearing, the movant shall serve copies of the motion on all other parties in accordance with §1.45 of this title (relating to Service in Protested Contested Cases).

(b) Replies to motions for rehearing must be filed not later than the 40th day after the date the decision or order that is subject of the motion is signed, or not later than the 10th day after the date a motion for rehearing is filed if the time for filing the motion for rehearing has been extended pursuant to subsection (e) of this section. On filing of the reply, copies of the reply shall be served on all other parties in accordance with §1.45 of this title.

(c) Motions for rehearing and replies to motions for rehearing may not be filed by fax or email unless permitted by the examiner or the Hearings director. The number of copies required to be filed will be determined by the examiner as noted in the notice to the parties issued with the proposal for decision. All copies shall be unstapled and three-hole punched for a three-ring binder.

(d) Commissioners shall act on a motion for rehearing not later than the 55th day after the date the decision or order that is the subject of the motion is signed or the motion for rehearing is overruled by operation of law.

(e) The deadline for filing a motion for rehearing may be extended as follows:

(1) The Commission may, on its own initiative or on the motion of any party for cause shown, by written order, extend the period of time for filing these motions and replies and for taking Commission action, provided that the Commission extends the time or takes the action not later than the 10th day after the date the period for filing a motion or reply or taking agency action expires. An extension shall not extend the period for Commission action beyond the 100th day after the date the decision or order that is the subject of the motion is signed. In the event of an extension, the motion for rehearing is overruled by operation of law on the date fixed by the order or, in the absence of a fixed date, on the 100th day after the decision or order that is the subject of the motion is signed;

(2) The parties may, by agreement and with the approval of the Commission, provide for a modification of the time periods provided in this section; or

(3) Pursuant to Texas Government Code, §2001.142.

(f) A subsequent motion for rehearing is not required after the Commission rules on a motion for rehearing unless the order disposing of the original motion for rehearing:

(1) modifies, corrects, or reforms in any respect the decision or order that is the subject of the complaint, other than a typographical, grammatical, or other clerical change identified as such by the agency in the order, including any modification, correction, or reformation that does not change the outcome of the contested case; or

(2) vacates the decision or order that is the subject of the motion and provides for a new decision or order.

(g) A subsequent motion for rehearing required by subsection (f) of this section must be filed not later than the 25th day after the date the order disposing of the original motion for rehearing is signed unless the deadline for filing the motion has been extended pursuant to applicable law.

Source Note: The provisions of this §1.128 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.129 Effect of Order Granting Rehearing

An order granting a motion for rehearing vacates the preceding final order. When the Commission renders a new final decision, a motion for rehearing directed to the new decision is a prerequisite to appeal.

Source Note: The provisions of this §1.129 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.130 Finality of Decisions or Orders

(a) A decision or order in a contested case is final:

(1) if a motion for rehearing is not filed on time, on the expiration of the period for filing a motion for rehearing;

(2) if a motion for rehearing is timely filed, on the date:

(A) the order denying the latest filed motion for rehearing is signed; or

(B) the latest filed motion for rehearing is overruled by operation of law;

(3) if the Commission finds that an imminent peril to the public health, safety, or welfare requires immediate effect of a decision or order, on the date the decision or order is signed, provided that the agency incorporates in the decision or order a factual and legal basis establishing an

imminent peril to the public health, safety, or welfare; or

(4) on:

(A) the date specified in the decision or order for a case in which all parties agree to the specified date in writing or on the record; or

(B) if the agreed specified date is before the date the decision or order is signed, the date the decision or order is signed.

(b) If a decision or order is final under subsection (a)(3) of this section, the Commission shall recite in the decision or order the finding made under that subsection and the fact that the decision or order is final and effective on the date signed.

Source Note: The provisions of this §1.130 adopted to be effective August 21, 2017, 42 TexReg 4131

§1.131 Administrative Record

The party appealing the Commission's order shall pay to the Commission the cost of preparing the original or a certified copy of the record prior to it being transmitted to the reviewing court at rates approved by the Office of the Attorney General of Texas. When more than one party appeals the Commission's order, the cost of the preparation of the record shall be divided equally among the appealing parties or as agreed by the parties.

Source Note: The provisions of this §1.131 adopted to be effective August 21, 2017, 42 TexReg 4131

SUBCHAPTER I PERMIT PROCESSING

§1.201 Time Periods for Processing Applications and Issuing Permits Administratively

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

Figure: 16 TAC §1.201(a) [*See Figure at end of this document.*]

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

(c) Time periods.

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

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

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

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

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

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

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

(A) administratively granted;

(B) administratively denied; or

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

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

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

(d) Complaint procedure.

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

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

Director may deny the relief requested by the complaint.

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

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

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

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

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

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

Source Note: The provisions of this §1.201 adopted to be effective May 14, 2001, 26 TexReg 3482; amended to be effective January 9, 2002, 27 TexReg 138; amended to be effective May 13, 2004, 29 TexReg 4469; amended to be effective January 6, 2025, 50 TexReg 31

SUBCHAPTER J RULEMAKING

§1.301 Petition for Adoption of Rules

(a) An interested person may petition the Commission requesting adoption of a rule. Petitions shall be in writing and filed with the Office of General Counsel.

(b) Each petition must state the name and address of the petitioner.

(c) Each petition shall include:

(1) a brief explanation of the proposed rule;

(2) the text of the proposed rule prepared in a manner to indicate the words to be added or deleted from the current text, if any;

(3) a statement of the statutory or other authority under which the rule is proposed to be promulgated; and

(4) a justification for adoption of the rule.

(d) For the purposes of this section, an interested person must be:

(1) a resident of this state;

(2) a business entity located in this state;

(3) a governmental subdivision located in this state; or

(4) a public or private organization located in this state that is not a state agency.

(e) The Office of General Counsel shall review all petitions for compliance with this section. If rejected, the petitioner may file a corrected petition that complies with the requirements of this section.

(f) Upon receipt of a petition that complies with the requirements of this section, the Office of General Counsel shall present the petition to the Commissioners with a recommendation on whether a rulemaking proceeding should be initiated.

(g) The Commissioners shall either deny the petition or approve initiation of rulemaking proceedings in accordance with the APA and these rules. The Commission may modify any proposed rule to ensure that it conforms to the format of Commission rules, adequately addresses the subject matter of the petition, and conforms to the filing requirements of the Texas Register.

Source Note: The provisions of this §1.301 adopted to be effective August 21, 2017, 42 TexReg 4131

Figure: 16 TAC §1.201(a)

Table 1. Initial and Final Review Periods for Permits Issued by the Railroad Commission of Texas, For Which Median Permit Processing Time Exceeds Seven Days

Rule and Permit **All references are to Title 16, Tex. Admin. Code**	**Division, Section Receiving Application**	**Initial Review Period**	**Final Review Period**
§3.6 (SWR 6), Application for Multiple Completion **Multiple Completion Authorization**	Oil and Gas Division, Administrative Compliance Section	60	10
§3.9 (SWR 9), Disposal Wells **Disposal Well Permits**	Oil and Gas Division, Injection-Storage Permits Section	30	15
§3.10 (SWR 10), Restriction of Production of Oil and Gas from Different Strata **Authority to Commingle**	Oil and Gas Division, Administrative Compliance Section	14	21
§3.23 (SWR 23), Vacuum Pumps **Authorization to Use Vacuum Pump**	Oil and Gas Division, Administrative Compliance Section	7	21
§3.41 (SWR 41), Application for New Oil or Gas Field Designation and/or Allowable **New Oil or Gas Field Designation and/or Allowable**	Oil and Gas Division, Administrative Compliance Section	14	7
§3.46 (SWR 46), Fluid Injection into Productive Reservoirs **Injection Permit**	Oil and Gas Division, Injection-Storage Permits Section	30	15
§3.46 (SWR 46), Fluid Injection into Productive Reservoirs **Injection Permit with Authorization to Inject Fresh Water**	Oil and Gas Division, Injection-Storage Permits Section	30	15
§3.46 (SWR 46), Fluid Injection into Productive Reservoirs **Area Permit**	Oil and Gas Division, Injection-Storage Permits Section	45	45
§3.48 (SWR 48), Capacity Oil Allowables for Secondary or Tertiary Recovery Projects **Capacity Oil Allowables**	Oil and Gas Division, Administrative Compliance Section	7	21
§3.50 (SWR 50), Enhanced Oil Recovery Projects Approval and Certification for Tax Incentive	Oil and Gas Division, Administrative Compliance Section	7	25

Rule and Permit All references are to Title 16, Tex. Admin. Code	Division, Section Receiving Application	Initial Review Period	Final Review Period
Certificate for Recovered Oil Tax Rate			
§3.50 (SWR 50) Enhanced Oil Recovery Projects Approval and Certification for Tax Incentive **Approval Concurrent With Recovered Oil Tax Rate**	Oil and Gas Division, Administrative Compliance Section	7	25
§3.50 (SWR 50), Enhanced Oil Recovery Projects Approval and Certification for Tax Incentive **Positive Production Response Certificate**	Oil and Gas Division, Administrative Compliance Section	7	25
§3.70 (SWR 70), Pipeline Permits Required **Permit to Operate a Pipeline**	Oversight and Safety Division, Pipeline Safety Department	15	15
§3.81 (SWR 81), Brine Mining Injection Wells **Brine Mining Injection Permit**	Oil and Gas Division, Technical Permitting Section	30	30
§3.83 (SWR 83), Tax Exemption for Two-and Three-year Inactive Wells **Certification of Inactivity**	Oil and Gas Division, Administrative Compliance Section	20	45
§3.93 (SWR 93), Water Quality Certification **401 Certification**	Oil and Gas Division, Technical Permitting Section	30	15
3.95 (SWR 95), Underground Storage of Liquid or Liquified Hydrocarbons in a Salt Formation **Permit to Create, Operate, and Maintain an Underground Hydrocarbon Storage Facility**	Oil and Gas Division, Technical Permitting Section	45	45
§3.96 (SWR 96), Underground Storage of Gas in Production or Depleted Reservoirs **Permit to Operate a Gas Storage Project**	Oil and Gas Division, Technical Permitting Section	45	45
§3.97 (SWR 97), Underground Storage of Gas in Salt Formations **Permit to Create, Operate, and Maintain an Underground Gas Storage Facility**	Oil and Gas Division, Technical Permitting Section	45	45
§3.101 (SWR 101), Certification for	Oil and Gas Division,		

Rule and Permit **All references are to Title 16, Tex. Admin. Code**	**Division, Section Receiving Application**	**Initial Review Period**	**Final Review Period**
Severance Tax Exemption for Gas Produced from High-Cost Gas Wells **Area Designation**	Administrative Compliance Section	7	45
§§4.120-4.135, 4.150-4.154 **Non-Commercial and Non-Centralized Pit Permits**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.120-4.135, §§4.140-4.143, and §§ 4.150-4.154 **Commercial or Centralized Pit Permits**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§4.120-4.135 **Non-Commercial and Non-Centralized Landfarming, Landtreatment**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.120-4.135, §§4.140-4.143, and §§4.160-4.164 **Commercial and Centralized Landfarming, Landtreatment**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.190-4.195 **Waste Hauler Permit**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	30	15
§4.182 **Minor Permit, Hydrostatic Test Discharge and other minor permits**	Oil and Gas Division, Technical Permitting/ Environmental Permitting, District Offices	15	15
§§4.120-4.135, §§4.140-4.143, and §§4.170-4.173 **Reclamation Plant Permit**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§4.184 **Non-Commercial Recycling Plant**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.202-4.211 **Commercial Recycling Plant**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.202-4.211, §§4.212-4.224 **Commercial On-Lease Solid Oil and Gas Waste Recycling**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90

Rule and Permit **All references are to Title 16, Tex. Admin. Code**	**Division, Section Receiving Application**	**Initial Review Period**	**Final Review Period**
§§4.202-4.211, §§4.230-4.245 **Commercial Off-Lease or Centralized Solid Oil and Gas Waste Recycling**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.202-4.211, §§4.247-4.261 **Commercial Stationary Solid Oil and Gas Waste Recycling**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.202-4.211, §§4.262-4.277 **Commercial Off-Lease Fluid Recycling**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§4.202-4.211, §§4.278-4.293 **Commercial Stationary Fluid Recycling**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§4.301, §4.302 **Beneficial Use of Drill Cutting Permits (Treatment and Recycling)**	Oil and Gas Division, Technical Permitting/ Environmental Permitting	45	90
§§5.201-5.208 **Permit to Construct a Geologic Storage Facility and Associated Class VI Injection Wells**	Oil and Gas Division, Technical Permitting Section	60	120
§§5.201-5.208 **Permit to Injection and Store Anthropogenic Carbon Dioxide**	Oil and Gas Division, Technical Permitting Section	60	120
Class V Closed-Loop Geothermal Injection Wells	Oil and Gas Division, Technical Permitting Section	15	15
§9.27, Application for an Exception to a Safety Rule **LPG Rule Exception**	Oversight and Safety Division, Alternative Fuels Safety Department	21	21
§9.54, Commission-Approved Outside Instructors-**LPG Outside Instructor Application**	Oversight and Safety Division, Alternative Fuels Safety Department	14	10
§9.101, Filings Required for Stationary LP-Gas Installations **LPG Plan Review**	Oversight and Safety Division, Alternative Fuels Safety Department	30	N/A
§11.93, Elements of Permit Application **New Permit Application**	Surface Mining and Reclamation Division	120	N/A
§11.97, Renewal **Permit Renewal**	Surface Mining and Reclamation Division	120	N/A

Rule and Permit **All references are to Title 16, Tex. Admin. Code**	**Division, Section Receiving Application**	**Initial Review Period**	**Final Review Period**
§11.98, Transfer **Permit Transfer**	Surface Mining and Reclamation Division	90	N/A
§11.114, Revision on Motion or with Consent **Permit Revision**	Surface Mining and Reclamation Division	120	N/A
§§11.131-11.137, Notice of Exploration Through Over-burden Removal; Content of Notice; Extraction of Minerals; Removal of Minerals; Lands Unsuitable for Surface Mining; Notice of Exploration Involving Hole Drilling; Permit **Uranium Exploration**	Surface Mining and Reclamation Division	30	30
§§11.205, 11.206, Changes in Coverage; Release or Reduction of Bonds **Bond Adjustment**	Surface Mining and Reclamation Division	90	N/A
§12.110, General Requirements: Exploration of less than 250 Tons **Coal Exploration < 250 Tons**	Surface Mining and Reclamation Division	90	N/A
§12.111, General Requirements: Exploration of More than 250 Tons **Coal Exploration > 250 Tons**	Surface Mining and Reclamation Division	120	N/A
§12.205, In Situ Processing Activities **In Situ Coal Gasification**	Surface Mining and Reclamation Division	120	N/A
§12.216, Criteria for Permit Approval or Denial **New Mine Permit**	Surface Mining and Reclamation Division	120	N/A
§12.226, Permit Revisions **Permit Revision-Administrative**	Surface Mining and Reclamation Division	60	N/A
§12.226, Permit Revisions **Permit Revision-Significant**	Surface Mining and Reclamation Division	120	N/A
§§12.227-12.230, Permit Renewals: General Requirements; Permit Renewals: Completed Applications; Permit Renewals: Terms; Permit Renewals: Approval or Denial **Permit Renewal**	Surface Mining and Reclamation Division	120	N/A

Rule and Permit **All references are to Title 16, Tex. Admin. Code**	**Division, Section Receiving Application**	**Initial Review Period**	**Final Review Period**
§§12.227-12.230, Permit Renewals: General Requirements; Permit Renewals: Completed Applications; Permit Renewals: Terms; Permit Renewals: Approval or Denial **Permit Renewal/Revision**	Surface Mining and Reclamation Division	120	N/A
§§12.231-12.233, Transfer, Assignment, or Sale of Permit Rights: General Requirements; Transfer, Assignment or Sale of Permit Rights: Obtaining Approval; Requirements for New Permits for Persons Succeeding to Rights Granted under a Permit **Permit Transfer**	Surface Mining and Reclamation Division	90	N/A
§12.307, Adjustment of Amount **Bond Adjustment**	Surface Mining and Reclamation Division	60	30
§12.707, Certification **Blaster Certification**	Surface Mining and Reclamation Division	90	N/A
13.25, Filings Required for Stationary CNG Installations – **CNG Plan Review**	Oversight and Safety Division, Alternative Fuels Safety Department	30	N/A
§13.35, Application for an Exception to a Safety Rule **CNG Rule Exception**	Oversight and Safety Division, Alternative Fuels Safety Department	21	21
§14.2019, Certification Requirements **LNG Employee Exam**	Oversight and Safety Division, Alternative Fuels Safety Department	10	N/A
§14.2040, Filings and Notice Requirements for Stationary LNG Installations **LNG Plan Review**	Oversight and Safety Division, Alternative Fuels Safety Department	30	N/A
§14.2052, Application for an Exception to a Safety Rule **LNG Rule Exception**	Oversight and Safety Division, Alternative Fuels Safety Department	21	21

TITLE 16 ECONOMIC REGULATION

PART 1 RAILROAD COMMISSION OF TEXAS

CHAPTER 3 OIL AND GAS DIVISION

§3.1 Organization Report; Retention of Records; Notice Requirements

(a) Filing requirements.

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

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

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

(C) discharging, storing, handling, transporting, reclaiming, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline;

(D) operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or repressurizing plants, or recycling plants;

(E) recovering skim oil from a salt water disposal site;

(F) nominating crude oil;

(G) operating a directional survey company;

(H) cleaning a reserve pit;

(I) operating a pipeline;

(J) operating as a cementer approved for plugging wells, operating as a cementer cementing casing strings or liners, or operating a well service company performing well stimulation activities, including hydraulic fracturing; or

(K) operating an underground hydrocarbon or natural gas storage facility.

(2) The Commission shall notify organizations that perform operations not included in paragraph (1)(A) - (K) of this subsection of any additional activities subject to the jurisdiction of the Commission which require the filing of the organization report. Such notification shall make the provisions of this section applicable to such activities.

(3) Each organization performing activities subject to the jurisdiction of the Commission shall maintain a current organization report with the Commission until all duties, obligations, and liabilities incurred pursuant to Commission rules, the Natural Resources Code, Titles 3 (Subtitles A, B, C, and Chapter 111 of Subtitle D) and 5, Texas Health and Safety Code, Chapter 401; Texas Utilities Code, §121.201, and the Water Code, Chapters 26, 27, and 29, are fulfilled.

(4) The organization report shall contain the following information:

(A) the name, street address, mailing address, telephone number, and emergency after-hours telephone number of the organization;

(B) the plan of the business organization;

(C) for each officer, director, general partner, owner of more than 25% ownership interest, or trustee (hereinafter controlling entity) of the organization:

(i) that entity's or individual's full legal name, the name(s) under which such entity or individual conducts business in the State of Texas, and all assumed names;

(ii) the following:

(I) if the entity is an individual, his or her social security number. Any individual who does not have a valid social security number shall submit, at that person's option, either his or her valid driver's license or Texas State Identification number;

(II) if the entity is not an individual, the name and, at that person's option, either the valid driver's license, social security, or Texas Identification number of each officer, director, or other person, who, under Texas Natural Resources Code, §91.114, holds a position of ownership or control of the organization, or an active P-5 number for that entity. All controlling entities connected to an organization which are not individuals shall provide the identification of the individuals in ownership or control of those entities.

(iii) a street address different than that of the organization; and

(iv) if different from the mailing address of the organization, a mailing address;

(D) if a foreign or nonresident organization, the name and street address of a resident agent.

(E) the name of any non-employee agent that the organization authorizes to act for the organization in signing Oil and Gas Division certificates of compliance which initially designate the operator or change the designation of the operator. Organizations may designate non-employee agents to execute subsequent organization reports. That designation shall be authorized by the organization and not by a non-employee agent.

(5) Any organization may designate a resident agent with a street address different than that of the organization in place of submitting the street addresses of the three (if applicable) primary controlling entities of the organization. Any foreign or nonresident organization identified in paragraph (1) of this subsection shall designate and maintain a resident agent upon whom may be served any process, notice, or demand required or permitted by law to be served upon such entity by or on behalf of the Commission. Failure of such organization to designate and maintain a resident agent shall render the organization report invalid. (Reference Order Number 20-60,617, effective January 1, 1971.)

(6) Failure by any organization identified in paragraph (1) of this subsection to answer any subpoena, commission to take deposition, or directive to appear at a hearing served upon such organization by or on behalf of the Commission shall render the organization report invalid.

(7) An organization shall refile an organization report annually according to the schedule assigned by the Commission. Prior to the filing date, the Commission shall mail notification and information to each organization for update of the organization report file. An organization shall file an amended organization report within 15 days after a change in any information required to be reported in the organization report. Only address changes may be made by letter.

(8) The Commission shall meet any requirement under statute or Commission rule for an order to be sent or notice to be given by the Commission to an organization by mailing the item to the organization's mailing address shown on the most recently filed organization report or the most recently filed letter notification of change of address. Notices sent by regular first-class mail shall be presumed to have been received if, upon arrival of the deadline for any response to the notice, the wrapper containing the notice has not been returned to the Commission. Any Commission action or proceeding for which notice is required shall go forward on the basis of the notice provided under this subsection, whether or not actual notice has been received. Service of notices and orders sent by certified mail is effective upon:

(A) acceptance of the item by any person at the address;

(B) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the Commission by the United States Postal Service; or

(C) return of the item to the Commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect.

(9) An organization may also designate to the Commission in writing a specified address for all Commission correspondence relating to a particular district. If designated by an operator, this specified address shall be used in lieu of the organization address for any notices, other than hearing notices, pertaining to that district.

(10) The Commission may return, unapproved, to the organization address an organization report which is submitted to the Commission not fully completed according to the report's written instructions and not timely corrected. In the event that the Commission returns an organization report, all submitted financial assurances shall remain non-refundable. If an organization report approved by the Commission is found to contain information that was materially false at the time it was submitted for approval, the Commission may suspend or revoke the organization report after notice and opportunity for hearing.

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

(c) Time frame. All organizations shall keep copies of records, forms, and documents which are required to be filed with the Commission, along with the supporting documents referred to in subsection (b) of this section, for a period of three years, or longer if required by another Commission rule, and any such copies may be disposed of at the discretion of such entities after the original records, forms, and documents have been on file with the Commission for the required period, except that particular documents shall be retained beyond the required period and until the resolution of pending Commission regulatory enforcement proceedings if the documents contain information material to the determination of any issues therein. All records, forms, and documents required to be filed with the Commission shall be filed in the same name, exactly as it appears on the organization report.

(d) Organization reports for operators of inactive wells.

(1) The Commission or its delegate may approve the

organization report for an operator of an inactive well if the Commission or its delegate has approved an extension of the deadline for plugging the inactive well.

(2) The Commission or its delegate may conditionally approve an organization report if:

(A) the operator assumed responsibility for a well that was inactive at the time of the approval of the operator designation form for the well; and

(B) the Commission or its delegate approved the operator designation form for the inactive well less than six months prior to the date the operator is required to renew its organization report.

(3) The Commission or its delegate may revoke conditional approval of an organization report granted under paragraph (2) of this subsection after notice of opportunity for hearing if the operator has failed to meet any of the following requirements within six months after approval of the operator designation form:

(A) restoration of the well to active status as defined by Commission rule;

(B) plugging of the well in compliance with a Commission rule or order; or

(C) obtaining the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

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

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

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

(f) Each organization required to file an organization report under subsection (a) of this section or an affiliate of such an organization that performs operations within the jurisdiction of the Commission that files for federal bankruptcy protection shall provide written notice to the Commission of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection by submitting the notice to the Enforcement Section of the Office of General Counsel. All bankruptcy-related notices sent to the Commission shall be submitted in writing to that section. For the purpose of this section, affiliate means an organization that is effectively controlled by another.

(g) Neither the Commission nor its delegate may approve an organization report unless the organization has complied with the state registration requirements of the Secretary of State. A tax dispute with the Comptroller of Public Accounts shall not be a basis for disapproving an organization report.

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

Source Note: The provisions of this §3.1 adopted to be effective January 1, 1976; amended to be effective January 1, 1981, 5 TexReg 4990; amended to be effective February 22, 1986, 11 TexReg 701; amended to be effective December 7, 1987, 12 TexReg 4411; amended to be effective July 22, 1991, 16 TexReg 3767; amended to be effective July 1, 1992, 17 TexReg 4173; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective January 11, 2004, 29 TexReg 359; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 27, 2012, 37 TexReg 6538.

§3.2 Commission Access to Properties

(a) The commission or its representatives shall have access to come upon any lease or property operated or controlled by an operator, producer, or transporter of oil, gas, or geothermal resources, and to inspect any and all leases, properties, and wells and all records of said leases, properties, and wells.

(b) Designated agents of the commission are authorized to make any tests on any well at any time necessary for conservation regulation, and the owner of such well is hereby directed to do all things that may be required of him by the commission's agent to make such tests in a proper manner.

Source Note: The provisions of this §3.2 adopted to be effective January 1, 1976; amended to be effective January 30, 2007, 32 TexReg 287.

§3.3 Identification of Properties, Wells, and Tanks

Each property that produces oil, gas, or geothermal resources and each oil, gas, or geothermal resource well and tank, or other approved crude oil measuring facility where tanks are not utilized thereon, shall at all times be clearly identified as follows.

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

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

(3) A sign shall be posted at or painted on each oil stock tank and on each remotely located satellite tank, or on each approved crude oil measuring facility where tanks are not utilized, that is located on or serving each property, which signs shall show, in addition to the information provided for in paragraph (1) of this section, the commission lease number for the formation from which oil in the tank, or in an approved crude oil measuring facility, is produced, and where oil from more than one formation is commingled in the same tank, or in an approved crude oil measuring facility, the sign shall show the number of the commission permit that authorized the commingling of the oil; provided that, if there is more than one tank in a battery which contains oil from only one formation or oil from different formations that is commingled pursuant to a single commingling permit, it will not be necessary for the sign to be posted at or painted on each tank if the sign posted at or painted on a tank in the battery shows the required information and clearly identifies, by tank number or otherwise, the tanks to which the information is applicable.

(4) If a well is separately completed in two or more producing formations, the wellhead valve and flow line serving each separate formation shall be identified by a metal tag or other lettering attached to or painted on either the valve or flow line which shows the name of the formation and identifies the completion string of casing or tubing, as for example "C" for casing; "UT" for upper tubing; "LT" for lower tubing, etc., each being preceded or followed by the name of the producing formation.

(5) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by paragraphs (1), (2), and (3) of this section shall be in letters and numbers at least one inch in height.

Source Note: The provisions of this §3.3 adopted to be effective January 1, 1976.

§3.4 Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms

(a) Lease name and number.

(1) All operators with oil and geothermal producing properties must ascertain from the appropriate proration schedule the lease number assigned to each separate lease, and thereafter include on each commission-required form or report the exact lease name and its number as they appear on the current proration schedule for all leases.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the lease name and lease number applicable thereto.

(3) If a lease has not been issued a lease number on the current proration schedule, the lease shall have assigned to it the exact lease name as shown on the form first submitted, and in addition thereto a lease number will be assigned at the same time the form reflecting the potential test is submitted and processed. Subsequent to the assignment of a lease number, such number together with the exact lease name as submitted on the appropriate form must appear on all future forms and reports submitted to the commission, the lease number and lease name as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the allowable for the lease.

(b) Gas well identification numbers shall be assigned by the commission for each separate gas well completion, and such gas well identification number shall be used on all forms and reports required by and filed with the commission concerning operations for such well so long as it remains a gas well, such commission gas well identification number to be effective as provided in the following paragraphs.

(1) All operators having a gas well must ascertain from the appropriate current gas allowable schedule the commission gas well identification number assigned to each separate gas well completion, and thereafter include on each commission required form or report its exact well lease name and number and its commission gas well identification number as they appear on the current gas allowable schedule for all gas wells completed in the same reservoir.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the well lease name and number and the commission gas well identification number applicable thereto.

(3) If a gas well has not been assigned a gas well identification number on the current gas allowable schedule, such well shall have assigned to it the exact well lease name and number as shown on the appropriate form and, in addition thereto, a gas well identification number will be assigned at the time the commission-required form is submitted and processed. After the assignment of a gas well identification number, such number together with the exact well lease name and number on the form first submitted, must appear on all future forms and reports submitted to the commission, the gas well lease name and gas well identification number as assigned by the commission to be evidenced to the operator on the face of

the supplement establishing the initial allowable for such well.

Source Note: The provisions of this §3.4 adopted to be effective January 1, 1976.

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

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

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

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

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

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(c) Commencement of operations. Operations of drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission and the waiting period, if any, has terminated, or authorization has been granted pursuant to subsection (d) of this section.

(d) Testing of existing wells in other reservoirs inside the casing. For an existing well, an operator may request authorization to commence operations to deepen inside the casing or plug back prior to the granting of a permit to deepen or plug back.

(1) This authorization shall be requested by submitting a request with the district office to deepen inside the casing or plug back. The request shall include:

(A) the operator name;

(B) the lease name;

(C) the lease number or gas identification number;

(D) well number;

(E) county;

(F) field name;

(G) a list of all reservoir(s) to be tested;

(H) the casing setting depth and the depth of the deepest reservoir to be tested;

(I) a plat showing the well location; and

(J) a statement as to whether or not the well location would require an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40) if completed in any of the reservoirs to be tested. If an exception would be required, the request shall also include a statement that all affected offsets have been given written notice of the intent to test with the opportunity to witness the testing and the offsets shall be identified on the plat.

(2) Operations of deepening inside the casing or plugging back shall not be commenced until the district office has reviewed and approved the request. Testing pursuant to this authorization shall be completed within 90 days from the date the district office approves the request.

(A) No reservoir tested pursuant to the provisions of this subsection shall be tested for more than 15 days.

(B) If the operator desires to place the well on production, the operator shall shut in the well, with no production being sold, and file a permit application for the tested reservoirs with the appropriate fees. If the permit application for the tested reservoirs requires an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), no consideration will be given by the commission to the cost of recompleting and testing the well in determining whether or not to grant the exception.

(C) Within 30 days of completion of testing, the operator must either file an application for a permit to produce a reservoir tested pursuant to this subsection or file an amended completion report in accordance with §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16) with a copy of the request signed by the district office and a statement that a

permit to produce a tested reservoir is not being sought, or if the well has been plugged and abandoned, a plugging report including reservoir and perforation data. If a permit is not obtained for the tested reservoirs and/or an allowable is not assigned, the producer shall report all test production on Form PR, Monthly Production Report, filed for the last permitted reservoir in which the well was completed and may request authorization to sell the test production. The test production may be sold after such authorization is granted.

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

(f) Drilling permit fee. With each application or materially amended application, the applicant shall submit to the commission a nonrefundable fee as determined by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(g) Expiration. Any permit to drill, deepen, plug back, or reenter granted by the commission expires no later than two years after the date of original approval.

(h) Plats. An application to drill, deepen, plug back, or reenter shall be accompanied by a neat, accurate plat, with a scale of one inch equals 1,000 feet. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or tract, including all tracts being pooled. If necessary to show the entire lease, the scale may be one inch equals 2,000 feet. Plats for subsequent wells on a lease or pooled unit shall show at least the lease or pooled unit line nearest the proposed location and the nearest survey/section lines. The Division Director or the director's delegate may approve plats with other scales upon request.

(1) The lease shall be outlined on the plat using either a heavy line or crosshatching.

(2) For vertical wells, the plat shall include the following:

(A) the surface location of the proposed drilling site;

(B) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from the two nearest non-parallel lease lines to the surface location;

(D) a line providing the distance in feet from the surface location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(E) a line providing the distance in feet from the surface location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information, including the Latitude/Longitude or X/Y coordinates in the NAD 27, NAD 83, or WGS 84 coordinate system;

(G) a labeled scale bar; and

(H) northerly direction.

(3) For horizontal wells, the plat shall include the following:

(A) the surface location of the proposed drilling site, penetration point, first take point, last take point, and terminus location;

(B) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from the two nearest non-parallel lease lines to the surface location; if location is offlease, then provide the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(D) a line providing the distance in feet from the horizontal wellbore between and including the penetration point and the terminus location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be indicated. A line providing the distance in feet from the horizontal wellbore between and including the first take point and the last take point to the nearest point on the lease line shall be indicated. If there are multiple leases, pooled units and/or unitized tracts closer to the horizontal course(s) of the drainhole(s) than allowed by the applicable spacing rule, then the operator shall provide the distance in feet from the closest take point to each such tract;

(E) a line providing the distance in feet from the wellbore from the penetration point through the terminus location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir. A line providing the

distance in feet from the wellbore between and including the first take point and the last take point to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information for the surface location of the well, including the Latitude/Longitude or X/Y coordinates in the NAD 27, NAD 83, or WGS 84 coordinate system;

(G) a labeled scale bar; and

(H) northerly direction.

(4) Requirements for plats as provided for in §3.11, §3.37, §3.38, and §3.86 of this title (relating to Inclination and Directional Surveys Required, Statewide Spacing Rule, Well Densities, and Horizontal Drainhole Wells) may supplement or replace the plat requirements set out above.

Source Note: The provisions of this §3.5 adopted to be effective January 1, 1976; amended to be effective September 1, 1983, 8 TexReg 3184; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective October 30, 1986, 11 TexReg 4214; amended to be effective February 24, 1992, 17 TexReg 1225; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective February 1, 2016, 41 TexReg 785.

§3.6 Application for Multiple Completion

(a) Authority will be granted to multicomplete a well in separate reservoirs that are not in communication without the necessity of notice and hearing on each separate application; provided, that an application for multiple completion on the form prescribed and the required accompanying data, as hereafter listed, is filed with the Engineering unit of the Commission's Permitting and Production Section for its consideration and approval.

(b) If the proposed zones of completion are not presently recognized by the commission as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the commission that the proposed zones of completion are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein must be filed with the application.

(c) If the additional data furnished with the application is not considered by the commission to be sufficient to establish the proposed zones of completion as separate zones of production which are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein, or if any party protests such an application, then, if an operator so elects, his application will be set for hearing.

(d) Multiple completion authority for a well will not be granted unless the following required data have been filed with the Engineering unit of the Commission's Permitting and Production Section:

(1) application for multiple completion properly executed and attested;

(2) electrical log or portion of the electric log of the well or a type electric log or a portion of the type electric log showing clearly thereon the subsurface location of the separate reservoirs claimed. Any electric log filed will be considered public information pursuant to §3.16 of this title (relating to Log and Completion Report (Statewide Rule 16);

(3) packer setting report where applicable;

(4) packer leakage test or communication test;

(5) diagrammatic sketch of the mechanical installation;

(6) letters of waiver from offset operators, or evidence that notice of application to multicomplete was given to said operators.

Source Note: The provisions of this §3.6 adopted to be effective January 1, 1976; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.7 Strata To Be Sealed Off

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

Source Note: The provisions of this §3.7 adopted to be effective January 1, 1976.

§3.8 Water Protection

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

(1) Basic sediment pit--Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. Basic sediment pits were formerly referred to as burn

pits.

(2) Brine pit--Pit used for storage of brine which is used to displace hydrocarbons from an underground hydrocarbon storage facility.

(3) Collecting pit--Pit used for storage of saltwater or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

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

(5) Drilling fluid disposal pit--Pit, other than a reserve pit, used for disposal of spent drilling fluid.

(6) Drilling fluid storage pit--Pit used for storage of drilling fluid which is not currently being used but which will be used in future drilling operations. Drilling fluid storage pits are often centrally located among several leases.

(7) Emergency saltwater storage pit--Pit used for storage of produced saltwater for limited period of time. Use of the pit is necessitated by a temporary shutdown of disposal well or fluid injection well and/or associated equipment, by temporary overflow of saltwater storage tanks on a producing lease or by a producing well loading up with formation fluids such that the well may die. Emergency saltwater storage pits may sometimes be referred to as emergency pits or blowdown pits.

(8) Flare pit--Pit which contains a flare and which is used for temporary storage of liquid hydrocarbons which are sent to the flare during equipment malfunction but which are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or a well.

(9) Fresh makeup water pit--Pit used in conjunction with a drilling rig for storage of fresh water used to make up drilling fluid or hydraulic fracturing fluid.

(10) Gas plant evaporation/retention pit--Pit used for storage or disposal of cooling tower blowdown, water condensed from natural gas, and other wastewater generated at gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants.

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

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

(13) Saltwater disposal pit--Pit used for disposal of produced saltwater.

(14) Skimming pit--Pit used for skimming oil off saltwater prior to disposal of saltwater at a disposal well or fluid injection well.

(15) Washout pit--Pit located at a truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.

(16) Water condensate pit--Pit used in conjunction with a gas pipeline drip or gas compressor station for storage or disposal of fresh water condensed from natural gas.

(17) Generator--Person who generates oil and gas wastes.

(18) Carrier--Person who transports oil and gas wastes generated by a generator. A carrier of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(19) Receiver--Person who stores, handles, treats, reclaims, or disposes of oil and gas wastes generated by a generator. A receiver of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(20) Director--Director of the Oil and Gas Division or his staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

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

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

(23) To dewater--To remove the free water.

(24) To dispose--To engage in any act of disposal subject to regulation by the commission including, but not limited to, conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, landfarming, or allowing to seep, or to cause or allow any such act of disposal.

(25) Landfarming--A waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area.

(26) Oil and gas wastes--Materials to be disposed of or reclaimed which have been generated in connection with

activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. The term "oil and gas wastes" includes waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants unless that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901 et seq.).

(27) Oil field fluids--Fluids to be used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and chemicals used to detoxify oil and gas wastes.

(28) Pollution of surface or subsurface water--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

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

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

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

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

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

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

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

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

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

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

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

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

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

(32) Brine mining pit--Pit, other than a fresh mining water pit, used in connection with activities associated with the solution mining of brine. Most brine mining pits are used to store mined brine.

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

(34) Inert wastes--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, fiberglass, and trash.

(35) Coastal zone--The area within the boundary established in Title 31, Texas Administrative Code, §503.1 (Coastal Management Program Boundary).

(36) Coastal management program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at Title 31, Texas Administrative Code, Chapters 501, 505, and 506.

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

(38) Coastal waters--Waters under tidal influence and waters of the open Gulf of Mexico.

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

(40) Practicable--Available and capable of being done after taking into consideration existing technology, cost, and logistics in light of the overall purpose of the activity.

(41) Non-commercial fluid recycling--The recycling of fluid produced from an oil or gas well, including produced formation fluid, workover fluid, and completion fluid, including fluids produced from the hydraulic fracturing process on an existing commission-designated lease or drilling unit associated with a commission-issued drilling permit or upon land leased or owned by the operator for the purposes of operation of a non-commercial disposal well operated pursuant to a permit issued under §3.9 of this title (relating to Disposal Wells) or a non-commercial injection well operated pursuant to a permit issued under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs), where the operator of the lease, or drilling unit, or non-commercial disposal or injection well treats or contracts with a person for the treatment of the fluid, and may accept such fluid from other leases and or operators.

(42) Non-commercial fluid recycling pit--Pit used in conjunction with one or more oil or gas leases or units that is constructed, maintained, and operated by the operator of record of the lease or unit and is located on an existing commission-designated lease or drilling unit associated with a commission-issued drilling permit, or upon land leased or owned by the operator for the purposes of operation of a non-commercial disposal well operated pursuant to a permit issued under §3.9 of this title or a non-commercial injection well operated pursuant to a permit issued under §3.46 of this title, for the storage of fluid for the purpose of non-commercial fluid recycling or for the storage of treated fluid.

(43) Recycle--To process and/or use or re-use oil and gas wastes as a product for which there is a legitimate commercial use and the actual use of the recyclable product. 'Recycle,' as defined in this subsection, does not include injection pursuant to a permit issued under §3.46 of this title.

(44) Treated fluid-Fluid that has been treated using water treatment technologies to remove impurities such that the treated fluid can be reused or recycled. Treated fluid is not a waste but may become a waste if it is abandoned or disposed of rather than reused or recycled.

(45) Recyclable product--A reusable material as defined in §4.204(12) of this title (relating to Definitions).

(46) 100-year flood plain--An area that is inundated by a 100-year flood, which is a flood that has a one percent or greater chance of occurring in any given year, as determined from maps or other data from the Federal Emergency Management Administration (FEMA), or, if not mapped by FEMA, from the United States Department of Agriculture soil maps.

(47) Distilled water--Water that has been purified by being heated to a vapor form and then condensed into another container as liquid water that is essentially free of all solutes.

(b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(c) Exploratory wells. Any oil, gas, or geothermal resource well or well drilled for exploratory purposes shall be governed by the provisions of statewide or field rules which are applicable and pertain to the drilling, safety, casing, production, abandoning, and plugging of wells.

(d) Pollution control.

(1) Prohibited disposal methods. Except for those disposal methods authorized for certain wastes by paragraph (3) of this subsection, subsection (e) of this section, or §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), or disposal methods required to be permitted pursuant to §3.9 of this title (relating to Disposal Wells) (Rule 9) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Rule 46), no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes. The disposal methods prohibited by this paragraph include, but are not limited to, the unpermitted discharge of oil field brines, geothermal resource waters, or other mineralized waters, or drilling fluids into any watercourse or drainageway, including any drainage ditch, dry creek, flowing creek, river, or any other body of surface water.

(2) Prohibited pits. No person may maintain or use any pit for storage of oil or oil products. Except as authorized by this subsection, no person may maintain or use any pit for storage of oil field fluids, or for storage or disposal of

oil and gas wastes, without obtaining a permit to maintain or use the pit. A person is not required to have a permit to use a pit if a receiver has such a permit, if the person complies with the terms of such permit while using the pit, and if the person has permission of the receiver to use the pit. The pits required by this paragraph to be permitted include, but are not limited to, the following types of pits: saltwater disposal pits; emergency saltwater storage pits; collecting pits; skimming pits; brine pits; brine mining pits; drilling fluid storage pits (other than mud circulation pits); drilling fluid disposal pits (other than reserve pits or slush pits); washout pits; and gas plant evaporation/retention pits. If a person maintains or uses a pit for storage of oil field fluids, or for storage or disposal of oil and gas wastes, and the use or maintenance of the pit is neither authorized by this subsection nor permitted, then the person maintaining or using the pit shall backfill and compact the pit in the time and manner required by the director. Prior to backfilling the pit, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(3) Authorized disposal methods.

(A) Fresh water condensate. A person may, without a permit, dispose of fresh water which has been condensed from natural gas and collected at gas pipeline drips or gas compressor stations, provided the disposal is by a method other than disposal into surface water of the state.

(B) Inert wastes. A person may, without a permit, dispose of inert and essentially insoluble oil and gas wastes including, but not limited to, concrete, glass, wood, and wire, provided the disposal is by a method other than disposal into surface water of the state.

(C) Low chloride drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by landfarming, provided the wastes are disposed of on the same lease where they are generated, and provided the person has the written permission of the surface owner of the tract where landfarming will occur: water base drilling fluids with a chloride concentration of 3,000 milligrams per liter (mg/liter) or less; drill cuttings, sands, and silts obtained while using water base drilling fluids with a chloride concentration of 3,000 mg/liter or less; and wash water used for cleaning drill pipe and other equipment at the well site.

(D) Other drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by burial, provided the wastes are disposed of at the same well site where they are generated: water base drilling fluid which had a chloride concentration in excess of 3,000 mg/liter but which have been dewatered; drill cuttings, sands, and silts obtained while using oil base drilling fluids or water base drilling fluids with a chloride concentration in excess of 3,000 mg/liter; and those drilling fluids and wastes allowed to be landfarmed without a permit.

(E) Completion/workover pit wastes. A person may, without a permit, dispose of the following oil and gas wastes by burial in a completion/workover pit, provided the wastes have been dewatered, and provided the wastes are disposed of at the same well site where they are generated: spent completion fluids, workover fluids, and the materials cleaned out of the wellbore of a well being completed or worked over.

(F) Contents of non-commercial fluid recycling pit. A person may, without a permit, dispose of the solids from a non-commercial fluid recycling pit by burial in the pit, provided the pit has been dewatered.

(G) Effect on backfilling. A person's choice to dispose of a waste by methods authorized by this paragraph shall not extend the time allowed for backfilling any reserve pit, mud circulation pit, or completion/workover pit whose use or maintenance is authorized by paragraph (4) of this subsection.

(4) Authorized pits. A person may, without a permit, maintain or use reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, fresh mining water pits, non-commercial fluid recycling pits, and water condensate pits on the following conditions.

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

(i) drilling fluids, whether fresh water base, saltwater base, or oil base;

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

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

(iv) drill stem test fluids; and

(v) blowout preventer test fluids.

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

(C) Basic sediment pits. A person shall not deposit or cause to be deposited into a basic sediment pit any oil field fluids or oil and gas wastes other than basic sediment removed from a production vessel or from the bottom of an oil storage tank. Although a person may store basic sediment in a basic sediment pit, a person may not deposit oil or free saltwater in the pit. The total capacity of a basic sediment pit shall not exceed a capacity of 50 barrels. The area covered by a basic sediment pit shall not exceed 250 square feet.

(D) Flare pits. A person shall not deposit or cause to

be deposited into a flare pit any oil field fluids or oil and gas wastes other than the hydrocarbons designed to go to the flare during upset conditions at the well, tank battery, or gas plant where the pit is located. A person shall not store liquid hydrocarbons in a flare pit for more than 48 hours at a time.

(E) Fresh makeup water pits and fresh mining water pits. A person shall not deposit or cause to be deposited into a fresh makeup water pit any oil and gas wastes or any oil field fluids other than fresh water used to make up drilling fluid or hydraulic fracturing fluid. A person shall not deposit or cause to be deposited into a fresh mining water pit any oil and gas wastes or any oil field fluids other than water used for solution mining of brine.

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

(G) Non-commercial fluid recycling pits.

(i) A person shall not deposit or cause to be deposited into a non-commercial fluid recycling pit any oil field fluids or oil and gas wastes other than those fluids described in subsection (a)(42) of this section.

(ii) All pits shall be sufficiently large to ensure adequate storage capacity and freeboard taking into account anticipated precipitation.

(iii) All pits shall be designed to prevent stormwater runoff from entering the pit. If a pit is constructed with a dike or berm, the height, slope, and construction material of such dike or berm shall be such that it is structurally sound and does not allow seepage.

(iv) A freeboard of at least two feet shall be maintained at all times.

(v) All pits shall be lined. The liner shall be designed, constructed, and installed to prevent any migration of materials from the pit into adjacent subsurface soils, ground water, or surface water at any time during the life of the pit. The liner shall be installed according to standard industry practices, shall be constructed of materials that have sufficient chemical and physical properties, including thickness, to prevent failure during the expected life of the pit. All liners shall have a hydraulic conductivity that is 1.0×10^{-7} cm/sec or less. A liner may be constructed of either natural or synthetic materials.

(I) Procedures shall be in place to routinely monitor the integrity of the liner of pit. If liner failure is discovered at any time, the pit shall be emptied and the liner repaired prior to placing the pit back in service. Acceptable monitoring procedures include an annual visual inspection of the pit liner or the installation of a double liner and leak detection system. Alternative monitoring procedures may be approved by the director if the operator demonstrates that the alternative is at least equivalent in the protection of surface and subsurface water as the provisions of this section.

(II) The liner of a pit with a single liner shall be inspected annually to ensure that the liner has not failed. This inspection shall be completed by emptying the pit and visually inspecting the liner.

(III) If the operator does not propose to empty the pit and inspect the pit liner on at least an annual basis, the operator shall install a double liner and leak detection system. A leak detection system shall be installed between a primary and secondary liner. The leak detection system must be monitored on a monthly basis to determine if the primary liner has failed. The primary liner has failed if the volume of water passing through the primary liner exceeds the action leakage rate, as calculated using accepted procedures, or 1,000 gallons per acre per day, whichever is larger.

(IV) The operator of the pit shall keep records to demonstrate compliance with the pit liner integrity requirements and shall make the records available to commission personnel upon request.

(vi) The operator of the pit shall provide written notification to the district director prior to construction of the pit, or prior to the use of an existing pit as a non-commercial fluid recycling pit. Such notification shall include:

(I) the location of the pit including the lease name and number or drilling permit number and the latitude and longitude;

(II) the dimensions and maximum capacity of the pit; and

(III) a signed statement that the operator has written permission from the surface owner of the tract upon which the pit is located for construction and use of the pit for such purpose.

(vii) Equipment, machinery, waste, or other materials that could reasonably be expected to puncture, tear, or otherwise compromise the integrity of the liner shall not be used or placed in lined pits.

(viii) The pit shall be inspected periodically by the operator for compliance with the applicable provisions of this section.

(H) Backfill requirements.

(i) A person who maintains or uses a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit shall dewater, backfill, and compact the pit according to the following schedule.

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

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

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

(IV) Basic sediment pits, flare pits, fresh mining water pits, non-commercial fluid recycling pits, and water condensate pits shall be dewatered, backfilled, and compacted within 120 days of final cessation of use of the pits.

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

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

(iii) The director may require that a person who uses or maintains a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit backfill the pit sooner than the time prescribed by clause (i) of this subparagraph if the director determines that oil and gas wastes or oil field fluids are likely to escape from the pit or that the pit is being used for improper storage or disposal of oil and gas wastes or oil field fluids.

(iv) Prior to backfilling any reserve pit, mud circulation pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit whose use or maintenance is authorized by this paragraph, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(I) Unless otherwise approved by the district director after a showing that the fluids will be confined in the pit at all times, all authorized pits shall be constructed, used, operated, and maintained at all times outside of a 100-year flood plain as that term is defined in subsection (a) of this section. The operator may request a hearing if the district director denies approval of the request to construct a pit within a 100-year flood plain.

(II) In the event of an unauthorized discharge from any pit authorized by this paragraph, the operator shall take any measures necessary to stop or control the discharge and report the discharge to the district office as soon as possible.

(5) Responsibility for disposal.

(A) Permit required. No generator or receiver may knowingly utilize the services of a carrier to transport oil and gas wastes if the carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No carrier may knowingly utilize the services of a second carrier to transport oil and gas wastes if the second carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No generator or carrier may knowingly utilize the services of a receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. No receiver may knowingly utilize the services of a second receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the second receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. Any person who plans to utilize the services of a carrier or receiver is under a duty to determine that the carrier or receiver has all permits required by the Oil and Gas Division to transport, store, handle, treat, reclaim, or dispose of oil and gas wastes.

(B) Improper disposal prohibited. No generator, carrier, receiver, or any other person may improperly dispose of oil and gas wastes or cause or allow the improper disposal of oil and gas wastes. A generator causes or allows the improper disposal of oil and gas wastes if:

(i) the generator utilizes the services of a carrier or receiver who improperly disposes of the wastes; and

(ii) the generator knew or reasonably should have known that the carrier or receiver was likely to improperly dispose of the wastes and failed to take reasonable steps to prevent the improper disposal.

(6) Permits.

(A) Standards for permit issuance. A permit to maintain or use a pit for storage of oil field fluids or oil and gas wastes may only be issued if the commission determines that the maintenance or use of such pit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface waters. A permit to dispose of oil and gas wastes by any method, including

disposal into a pit, may only be issued if the commission determines that the disposal will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water. A permit to maintain or use any unlined brine mining pit or any unlined pit, other than an emergency saltwater storage pit, for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters may only be issued if the commission determines that the applicant has conclusively shown that use of the pit cannot cause pollution of surrounding productive agricultural land nor pollution of surface or subsurface water, either because there is no surface or subsurface water in the area of the pit, or because the surface or subsurface water in the area of the pit would be physically isolated by naturally occurring impervious barriers from any oil and gas wastes which might escape or migrate from the pit. Permits issued pursuant to this paragraph will contain conditions reasonably necessary to prevent the waste of oil, gas, or geothermal resources and the pollution of surface and subsurface waters. A permit to maintain or use a pit will state the conditions under which the pit may be operated, including the conditions under which the permittee shall be required to dewater, backfill, and compact the pit. Any permits issued pursuant to this paragraph may contain requirements concerning the design and construction of pits and disposal facilities, including requirements relating to pit construction materials, dike design, liner material, liner thickness, procedures for installing liners, schedules for inspecting and/or replacing liners, overflow warning devices, leak detection devices, and fences. However, a permit to maintain or use any lined brine mining pit or any lined pit for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters will contain requirements relating to liner material, liner thickness, procedures for installing liners, and schedules for inspecting and/or replacing liners.

(B) Application. An application for a permit to maintain or use a pit or to dispose of oil and gas wastes shall be filed with the commission in Austin. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the original application is mailed or delivered to the commission in Austin. A permit application shall be considered filed with the commission on the date it is received by the commission in Austin. When a commission-prescribed application form exists, an applicant shall make application on the prescribed form according to the instructions on such form. The director may require the applicant to provide the commission with engineering, geological, or other information which the director deems necessary to show that issuance of the permit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water.

(C) Notice. The applicant shall give notice of the permit application to the surface owners of the tract upon which the pit will be located or upon which the disposal will take place. When the tract upon which the pit will be located or upon which the disposal will take place lies within the corporate limits of an incorporated city, town, or village, the applicant shall also give notice to the city clerk or other appropriate official. Where disposal is to be by discharge into a watercourse other than the Gulf of Mexico or a bay, the applicant shall also give notice to the surface owners of each waterfront tract between the discharge point and 1/2 mile downstream of the discharge point except for those waterfront tracts within the corporate limits of an incorporated city, town, or village. When one or more waterfront tracts within 1/2 mile of the discharge point lie within the corporate limits of an incorporated city, town, or village, the applicant shall give notice to the city clerk or other appropriate official. Notice of the permit application shall consist of a copy of the application together 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. The applicant shall mail or deliver the required notice to the surface owners and the city clerk or other appropriate official on or before the date the application is mailed or delivered to the commission in Austin. If, in connection with a particular application, the director determines that another class of persons, such as offset operators, adjacent surface owners, or an appropriate river authority, should receive notice of the application, the director may require the applicant to mail or deliver notice to members of that class. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the director may authorize the applicant to notify such persons by publishing notice of the application. The director shall determine the form of the notice to be published. The notice shall be published once each week for two consecutive weeks by the applicant in a newspaper of general circulation in the county where the pit will be located or the disposal will take place. The applicant shall file proof of publication with the commission in Austin. The director will consider the applicant to have made diligent efforts to ascertain the names and addresses of surface owners required by this subparagraph to be notified if the applicant has examined the current county tax rolls and investigated other reliable and readily available sources of information.

(D) Protests and hearings. If a protest from an affected person is made to the commission within 15 days of the date the application is filed, then a hearing shall be held on the application after the applicant requests a hearing. If the director has reason to believe that a person entitled to notice of an application has not received such notice within 15 days of the date an application is filed with the commission, then the director shall not take action on the application until reasonable efforts have been made to give such person notice of the application and an opportunity to file a protest to the application. If the director determines that a hearing is in the public interest, a hearing shall be held. A hearing on an application shall be held after the commission provides notice of hearing to all affected persons, or other persons or governmental entities who express an interest in the application in writing. If no protest from an affected person is received by the commission, the director may administratively approve the application. If the director denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the hearings examiner shall recommend a final action by the commission.

(E) Modification, suspension, and termination. A permit granted pursuant to this subsection, may be modified, suspended, or terminated by the commission for good cause after notice and opportunity for hearing. A finding of any of the following facts shall constitute good cause:

(i) pollution of surface or subsurface water is occurring or is likely to occur as a result of the permitted operations;

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

(iii) the permittee has violated the terms and conditions of the permit or commission rules;

(iv) the permittee misrepresented any material fact during the permit issuance process;

(v) the permittee failed to give the notice required by the commission during the permit issuance process;

(vi) a material change of conditions has occurred in the permitted operations, or the information provided in the application has changed materially.

(F) Emergency permits. If the director determines that expeditious issuance of the permit will prevent or is likely to prevent the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water, the director may issue an emergency permit. An application for an emergency permit to use or maintain a pit or to dispose of oil and gas wastes shall be filed with the commission in the appropriate district office. Notice of the application is not required. If warranted by the nature of the emergency, the director may issue an emergency permit based upon a verbal application, or the director may verbally authorize an activity before issuing a written permit authorizing that activity. An emergency permit is valid for up to 30 days, but may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of an emergency permit shall be governed by the provisions of subparagraphs (A) - (E) of this paragraph.

(G) Minor permits. If the director determines that an application is for a permit to store only a minor amount of oil field fluids or to store or dispose of only a minor amount of oil and gas waste, the director may issue a minor permit provided the permit does not authorize an activity which results in waste of oil, gas, or geothermal resources or pollution of surface or subsurface water. An application for a minor permit shall be filed with the commission in the appropriate district office. Notice of the application shall be given as required by the director. The director may determine that notice of the application is not required. A minor permit is valid for 60 days, but a minor permit which is issued without notice of the application may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of a minor permit shall be governed by the provisions of subparagraphs (A) - (E) of this paragraph.

(7) Recycling.

(A) Prohibited recycling. Except for those recycling methods authorized for certain wastes by subparagraph (B) of this paragraph, no person may recycle any oil and gas wastes by any method without obtaining a permit.

(B) Authorized recycling.

(i) No permit is required if treated fluid is recycled for use as makeup water for a hydraulic fracturing fluid treatment(s), or as another type of oilfield fluid to be used in the wellbore of an oil, gas, geothermal, or service well.

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

(iii) If treatment of the fluid results in distilled water, no permit is required to use the resulting distilled water in any manner other than discharge to waters of the state.

(iv) Fluid that meets the requirements of clause (i), (ii), or (iii) of this subparagraph is a recyclable product.

(C) Permitted recycling.

(i) Treated fluid may be reused in any manner, other than the manner authorized by subparagraph (B) of this paragraph, pursuant to a permit issued by the director on a case-by-case basis, taking into account the source of the fluids, the anticipated constituents of concern, the volume of fluids, the location, and the proposed reuse of the treated fluids. Fluid that meets the requirements of a permit issued under this clause is a recyclable product.

(ii) All commercial recycling requires the commercial recycler of the oil and gas waste to obtain a permit in accordance with Chapter 4, Subchapter B of this title (relating to Commercial Recycling).

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

(e) Pollution prevention (reference Order Number 20-59,200, effective May 1, 1969).

(1) The operator shall not pollute the waters of the Texas offshore and adjacent estuarine zones (saltwater

bearing bays, inlets, and estuaries) or damage the aquatic life therein.

(2) All oil, gas, and geothermal resource well drilling and producing operations shall be conducted in such a manner to preclude the pollution of the waters of the Texas offshore and adjacent estuarine zones. Particularly, the following procedures shall be utilized to prevent pollution.

(A) The disposal of liquid waste material into the Texas offshore and adjacent estuarine zones shall be limited to saltwater and other materials which have been treated, when necessary, for the removal of constituents which may be harmful to aquatic life or injurious to life or property.

(B) No oil or other hydrocarbons in any form or combination with other materials or constituent shall be disposed of into the Texas offshore and adjacent estuarine zones.

(C) All deck areas on drilling platforms, barges, workover unit, and associated equipment both floating and stationary subject to contamination shall be either curbed and connected by drain to a collecting tank, sump, or enclosed drilling slot in which the containment will be treated and disposed of without causing hazard or pollution; or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks, sumps, or enclosed drilling slots to prevent overflow or prevent pollution of the surrounding water.

(D) Solid combustible waste may be burned and the ashes may be disposed of into Texas offshore and adjacent estuarine zones. Solid wastes such as cans, bottles, or any form of trash must be transported to shore in appropriate containers. Edible garbage, which may be consumed by aquatic life without harm, may be disposed of into Texas offshore and adjacent estuarine zones.

(E) Drilling muds which contain oil shall be transported to shore or a designated area for disposal. Only oil-free cutting and fluids from mud systems may be disposed of into Texas offshore and adjacent estuarine zones at or near the surface.

(F) Fluids produced from offshore wells shall be mechanically contained in adequately pressure-controlled piping or vessels from producing well to disposition point. Oil and water separation facilities at offshore and onshore locations shall contain safeguards to prevent emission of pollutants to the Texas offshore and adjacent estuarine zones prior to proper treatment.

(G) All deck areas on producing platforms subject to contamination shall be either curbed and connected by drain to a collecting tank or sump in which the containment will be treated and disposed of without causing hazard or pollution, or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks or sumps designed to accommodate all reasonably expected drainage. Satisfactory means must be provided to empty the sumps to prevent overflow.

(H) Any person observing water pollution shall report such sighting, noting size, material, location, and current conditions to the ranking operating personnel. Immediate action or notification shall be made to eliminate further pollution. The operator shall then transmit the report to the appropriate commission district office.

(I) Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator.

(3) The commission may suspend producing and/or drilling operations from any facility when it appears that the provisions of this rule are being violated.

(4) (Reference Order Number 20-60,214, effective October 1, 1970.) The foregoing provisions of Rule 8 (D) shall also be required and enforced as to all oil, gas, or geothermal resource operations conducted on the inland and fresh waters of the State of Texas, such as lakes, rivers, and streams.

(f) Oil and gas waste haulers.

(1) A person who transports oil and gas waste for hire by any method other than by pipeline shall not haul or dispose of oil and gas waste off a lease, unit, or other oil or gas property where it is generated unless such transporter has qualified for and been issued an oil and gas waste hauler permit by the commission. Hauling of inert waste, asbestos-containing material regulated under the Clean Air Act (42 USC §§7401 et seq), polychlorinated biphenyl (PCB) waste regulated under the Toxic Substances Control Act (15 USCA §§2601 et seq), or hazardous oil and gas waste subject to regulation under §3.98 of this title is excluded from this subsection. This subsection is not applicable to the non-commercial hauling of oil and gas wastes for non-commercial recycling. For purposes of this subsection, injection of salt water or other oil and gas waste into an oil and gas reservoir for purposes of enhanced recovery does not qualify as recycling.

(A) Application for an oil and gas waste hauler permit will be made on the commission-prescribed form, and in accordance with the instructions thereon, and must be accompanied by:

(i) the permit application fee required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78);

(ii) vehicle identification information to support

commission issuance of an approved vehicle list;

(iii) an affidavit from the operator of each commission-permitted disposal system the hauler intends to use stating that the hauler has permission to use the system; and

(iv) a certification by the hauler that the vehicles listed on the application are designed so that they will not leak during transportation. The certification shall include a statement that vehicles used to haul non-solid oil and gas waste shall be designed to transport non-solid oil and gas wastes, and shall be operated and maintained to prevent the escape of oil and gas waste.

(B) An oil and gas waste hauler permit may be issued for a term not to exceed one year, subject to renewal by the filing of an application for permit renewal and the required application fee for the next permit period. The term of an oil and gas waste hauler permit will be established in accordance with a schedule prescribed by the director to allow for the orderly and timely renewal of oil and gas waste hauler permits on a staggered basis.

(C) Each oil and gas waste hauler shall operate in strict compliance with the instructions and conditions stated on the permit which provide:

(i) This permit, unless suspended or revoked for cause shown, shall remain valid until the expiration date specified in this permit.

(ii) Each vehicle used by a permittee shall be marked on both sides and the rear with the permittee's name and permit number in characters not less than three inches high. (For the purposes of this permit, "vehicle" means any truck tank, trailer tank, tank car, vacuum truck, dump truck, garbage truck, or other container in which oil and gas waste will be hauled by the permittee.)

(iii) Each vehicle must carry a copy of the permit including those parts of the commission-issued attachments listing approved vehicles and commission-permitted disposal systems that are relevant to that vehicle's activities. This permit authority is limited to those vehicles shown on the commission-issued list of approved vehicles.

(iv) This permit is issued pursuant to the information furnished on the application form, and any change in conditions must be reported to the commission on an amended application form. The permit authority will be revised as required by the amended application.

(v) This permit authority is limited to hauling, handling, and disposal of oil and gas waste.

(vi) This permit authorizes the permittee to use commission-permitted disposal systems for which the permittee has submitted affidavits from the disposal system operators stating that the permittee has permission to use the systems. These disposal systems are listed as an attachment to the permit. This permit also authorizes the permittee to use a disposal system operated under authority of a minor permit issued by the commission without submitting an affidavit from the disposal system operator. In addition, this permit authorizes the permittee to transport hazardous oil and gas waste to any facility in accordance with the provisions of §3.98 of this title, provided the shipment is accompanied by a manifest. Finally, this permit authorizes the transportation of oil and gas waste to a disposal facility permitted by another agency or another state provided the commission has granted separate authorization for the disposal.

(vii) The permittee must file an application for a renewal permit, using the permittee's assigned permit number, before the expiration date specified in this permit.

(viii) The permittee must compile and keep current a list of all persons by whom the permittee is hired to haul and dispose of oil and gas waste, and furnish such list to the commission upon request.

(ix) Each vehicle must be operated and maintained in such a manner as to prevent spillage, leakage, or other escape of oil and gas waste during transportation. Vehicles used to haul non-solid oil and gas waste shall be designed to transport non-solid oil and gas wastes, and shall be operated and maintained to prevent the escape of oil and gas waste.

(x) Each vehicle must be made available for inspection upon request by commission personnel.

(2) A record shall be kept by each oil and gas waste hauler showing daily oil and gas waste hauling operations under the permitted authority.

(A) Such daily record shall be dated and signed by the vehicle driver and shall show the following information:

(i) identity of the property from which the oil and gas waste is hauled;

(ii) identity of the disposal system or commercial recycling facility to which the oil and gas waste is delivered;

(iii) the type and volume of oil and gas waste received by the hauler at the property where it was generated; and

(iv) the type and volume of oil and gas waste transported and delivered by the hauler to the disposal system or commercial recycling facility.

(B) Such record shall be kept open for the inspection of the commission or its representatives.

(C) Such record shall be kept on file for a period of three years from the date of operation and recordation.

(g) Recordkeeping.

(1) Oil and gas waste. When oil and gas waste is hauled by vehicle from the lease, unit, or other oil or gas property where it is generated to an off-lease disposal or recycling facility, the person generating the oil and gas waste shall keep, for a period of three years from the date of generation, the following records:

(A) identity of the property from which the oil and gas waste is hauled;

(B) identity of the disposal system or recycling facility to which the oil and gas waste is delivered;

(C) name and address of the hauler, and permit number (WHP number) if applicable; and

(D) type and volume of oil and gas waste transported each day to disposal or recycling.

(2) Retention of run tickets. A person may comply with the requirements of paragraph (1) of this subsection by retaining run tickets or other billing information created by the oil and gas waste hauler, provided the run tickets or other billing information contain all the information required by paragraph (1) of this subsection.

(3) Examination and reporting. The person keeping any records required by this subsection shall make the records available for examination and copying by members and employees of the commission during reasonable working hours. Upon request of the commission, the person keeping the records shall file such records with the commission.

(h) Penalties. Violations of this section may subject a person to penalties and remedies specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the commission. 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) (Rule 73) or violation of this section.

(i) Coordination between the Railroad Commission of Texas and the Texas Commission on Environmental Quality or its successor agencies. The Railroad Commission and the Texas Commission on Environmental Quality both have adopted by rule a memorandum of understanding regarding the division of jurisdiction between the agencies over wastes that result from, or are related to, activities associated with the exploration, development, and production of oil, gas, or geothermal resources, and the refining of oil. The memorandum of understanding is adopted in §3.30 of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(j) Consistency with the Texas Coastal Management Program. The provisions of this subsection apply only to activities that occur in the coastal zone and that are subject to the CMP rules.

(1) Specific Policies.

(A) Disposal of Oil and Gas Waste in Pits. The following provisions apply to oil and gas waste disposal pits located in the coastal zone:

(i) no commercial oil and gas waste disposal pit constructed after the effective date of this subsection shall be located in any CNRA; and

(ii) all oil and gas waste disposal pits shall be designed to prevent releases of pollutants that adversely affect coastal waters or critical areas.

(B) Discharge of Oil and Gas Waste to Surface Waters. The following provisions apply to discharges of oil and gas waste that occur in the coastal zone:

(i) no discharge of oil and gas waste to surface waters may cause a violation of the Texas Surface Water Quality Standards adopted by the Texas Commission on Environmental Quality or its successor agencies and codified at Title 30, Texas Administrative Code, Chapter 307;

(ii) in determining whether any permit to discharge oil and gas waste that is comprised, in whole or in part, of produced water is consistent with the goals and policies of the CMP, the commission shall consider the effects of salinity from the discharge;

(iii) to the greatest extent practicable, in the case of any oil and gas exploration, production, or development operation from which an oil and gas waste discharge commences after the effective date this subsection, the outfall for the discharge shall not be located where the discharge will adversely affect any critical area;

(iv) in the case of any oil and gas exploration, production, or development operation with an oil and gas waste discharge permitted prior to the effective date of this subsection that adversely affects any critical area, the outfall for the discharge shall either:

(I) be relocated within two years after the effective date of this subsection, so that, to the greatest extent practicable, the discharge does not adversely affect any critical area; or

(II) the discharge shall be discontinued; and

(v) the commission shall notify the Texas Commission on Environmental Quality or its successor agencies and the Texas Parks and Wildlife Department upon receipt of an application for a permit to discharge oil and gas waste that is comprised, in whole or in part, of produced waters to waters under tidal influence.

(C) Development in Critical Areas. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable

water quality requirements for federal permits authorizing development affecting critical areas. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(h)(1)(A) - (G), have been satisfied. The commission shall coordinate its efforts under this subparagraph with those of other appropriate state and federal agencies.

(D) Dredging and Dredged Material Disposal and Placement. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable water quality requirements for federal permits authorizing dredging and dredged material disposal and placement in the coastal zone. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(j), have been satisfied.

(2) Consistency Determinations. The provisions of this paragraph apply to issuance of determinations required under Title 31, Texas Administrative Code, §505.30 (Agency Consistency Determination), for the following actions listed in Title 31, Texas Administrative Code, §505.11(a)(3): permits to dispose of oil and gas waste in a pit; permits to discharge oil and gas wastes to surface waters; and certifications of compliance with applicable water quality requirements for federal permits for development in critical areas and dredging and dredged material disposal and placement in the coastal area.

(A) The commission shall issue consistency determinations under this paragraph as an element of the permitting process for permits to dispose of oil and gas waste in a pit and permits to discharge oil and gas waste to surface waters.

(B) Prior to issuance of a permit or certification covered by this paragraph, the commission shall determine if the proposed activity will have a direct and significant adverse effect on any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to such activity.

(i) If the commission determines that issuance of a permit or a certification covered by this paragraph would not result in direct and significant adverse effects to any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall issue a written determination of no direct and significant adverse effect which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Coastal Management Program (CMP) goals and policies, and has found that the proposed action will not have a direct and significant adverse affect on any coastal natural resource area (CNRA) identified in the applicable policies."

(ii) If the commission determines that issuance of a permit or certification covered by this paragraph would result in direct and significant adverse affects to a CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall determine whether the proposed activity would meet the applicable requirements of paragraph (1) of this subsection.

(I) If the commission determines that the proposed activity would meet the applicable requirements of paragraph (1) of this subsection, the commission shall issue a written consistency determination which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Texas Coastal Management Program (CMP) goals and policies, and has determined that the proposed action is consistent with the applicable CMP goals and policies."

(II) If the commission determines that the proposed activity would not meet the applicable requirements of paragraph (1) of this subsection, the commission shall not issue the permit or certification.

(3) Thresholds for Referral. Any commission action that is not identified in this paragraph shall be deemed not to exceed thresholds for referral for purposes of the CMP rules. Pursuant to Title 31, Texas Administrative Code, §505.32 (Requirements for Referral of an Individual Agency Action), the thresholds for referral of consistency determinations issued by the commission are as follows:

(A) for oil and gas waste disposal pits, any permit to construct a pit occupying five acres or more of any CNRA that has been mapped or that may be readily determined by a survey of the site;

(B) for discharges, any permit to discharge oil and gas waste consisting, in whole or in part, of produced waters into tidally influenced waters at a rate equal to or greater than 100,000 gallons per day;

(C) for certification of federal permits for development in critical areas:

(i) in the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of:

(I) ten acres or more of submerged aquatic vegetation or tidal sand or mud flats; or

(II) five acres or more of any other critical area; and

(ii) in all areas within the coastal zone other than the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of five acres or more of any critical area;

(D) for certification of federal permits for dredging and dredged material disposal or placement, certification of a permit authorizing removal of more than 10,000 cubic yards of dredged material from a critical area.

Source Note: The provisions of this §3.8 adopted to be effective January 1, 1976; amended to be effective February 10, 1977, 2 TexReg 359; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective May 1, 1984, 9 TexReg 1549; amended to be effective March 15, 1986, 11 TexReg 950; amended to be effective January 6, 1987, 11 TexReg 5091; amended to be effective December 1, 1987, 12 TexReg 4188; amended to be effective January 28, 1992, 17 TexReg 321; amended to be effective February 1, 1995, 19 TexReg 10345; amended to be effective October 25, 1995, 20 TexReg 8442; amended to be effective April 1, 1996, 20 TexReg 9423; amended to be effective July 10, 2000, 25 TexReg 6487; amended tobe effective September 1, 2004, 29 TexReg 8271; amended to be effective April 15, 2013, 38 TexReg 2318.

§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.

Source Note: The provisions of this §3.9 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective April 1, 1982, 7 TexReg 651; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.10 Restriction of Production of Oil and Gas from Different Strata

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of tubulars except as provided in this section. As used in this section, "different strata" means two or more different commission-designated fields, or one or more commission-designated fields and any other hydrocarbon reservoir.

(b) Exception. After notice and an opportunity for a hearing, the commission or its delegate may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from different strata, if commingled production will prevent waste or promote conservation or protect correlative rights.

(c) Notice of Application for Exception.

(1) Timing of Notice.

(A) The applicant shall give notice of each request for an exception by serving a copy of the application to commingle production on all affected operators at the same time the application is filed with the commission.

(B) Service shall be accomplished by delivering a copy of the application to the operator to be served, or to the operator's duly authorized representative, in person, by agent, by courier receipted delivery, by first class mail to the operator's mailing address as shown on the operator's most recently filed Form P-5 (Organization Report) or the most recently filed letter notification of change of address, or by such other manner as the commission may direct.

(2) Operators Presumptively Affected By Application.

(A) An initial exception to commingle production exclusively from different commission-designated fields is

presumed to affect all operators in each of the commission-designated fields proposed to be produced through the same string of tubulars.

(B) An initial exception to commingle production from a commission-designated field with production from one or more hydrocarbon reservoirs that have not been designated by the commission as a field is presumed to affect all operators in each of the different commission-designated fields proposed to be produced through the same string of tubulars and all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(C) An exception to commingle production exclusively from the same commission-designated fields for which an initial commingling application has previously been granted is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a subsequent commingling exception is sought than the longest applicable minimum lease-line distance, who have a well completed in one or more of the commission-designated fields for which commingling is sought.

(D) An exception to commingle production from a commission-designated field and one or more hydrocarbon reservoirs in specified correlative intervals that have not been designated by the commission as fields, for which an initial commingling exception involving the same fields and hydrocarbon reservoirs has previously been granted, is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(3) Notice Required Only to Affected Operators.

(A) Except as provided in subparagraph (B) of this paragraph, all operators described in paragraph (2)(A) - (D) of this subsection are affected by a requested exception to allow commingling and the applicant shall give each of them notice of the application as provided in paragraph (1)(A) of this subsection.

(B) The commission or its delegate may determine that an operator described in paragraph (2)(A) - (D) will be unaffected by a requested exception to allow commingling. This determination shall be made only upon the applicant's written request and provision to the commission of competent geological or engineering data establishing conclusively that commingling production as requested by the applicant will not physically interfere with the production of hydrocarbons by the operator for which an unaffected determination is requested. An applicant for an exception to allow commingling is not required to give notice of the application to an operator who has been determined to be unaffected as provided in this subparagraph.

(d) Commingled production. Commingled production of gas from different strata pursuant to subsection (b) of this section shall be considered production from a common source of supply for purposes of proration and allocation.

Source Note: The provisions of this §3.10 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective September 12, 1979, 4 TexReg 3082; amended to be effective May 14, 1996, 21 TexReg 3791.

§3.11 Inclination and Directional Surveys Required

(a) General. All wells shall be drilled as nearly vertical as possible by normal, prudent, practical drilling operations. Nothing in this section shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease and/or property lines (or unit lines in cases of pooling) without special permission.

(b) Inclination surveys.

(1) Requirements.

(A) An inclination survey made by persons or concerns approved by the commission shall be filed on a form prescribed by the commission for each well drilled or deepened with rotary tools, except as hereinafter provided, or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

(B) Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

(C) Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed as a part of or in addition to the inclination surveys otherwise required by this section. If computations are made from dipmeter surveys to determine the course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

(D) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

(E) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser, and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

(F) Inclination surveys will not be required on wells that are drilled and completed as dry holes and are

permanently plugged and abandoned. If such wells are reentered at a later date and completed as producers or injection or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

(G) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with the Railroad Commission of Texas (commission). If such data are not on file with the commission, the results of an inclination survey must be reported on the appropriate form and filed with the completion form, except as provided by subparagraph (D) of this paragraph.

(2) Reports.

(A) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points, assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point, and the total possible accumulative drift, assuming that all measured angles of inclination are in the same direction.

(B) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at his direction on his behalf, either:

(i) that the well was not intentionally deviated from vertical; or

(ii) that the well was deviated at random, with an explanation of the circumstances.

(C) The report shall be filed in the district office by attaching one copy to each appropriate completion form for the well.

(D) The commission may require the submittal of the original charts, graphs, or discs resulting from the surveys.

(c) Directional surveys.

(1) When required.

(A) When the maximum displacement indicated by an inclination survey is greater than the actual distance from the surface location to the nearest lease line or pooled unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at his own expense by a commission approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When such directional survey shows the well to be bottomed within the confines of the lease, but nearer to a well or lease line or pooled unit boundary than allowed by applicable rules, or by the permit for the well if the well has been granted an exception to §3.37 of this title (relating to Statewide Spacing Rule), a new permit will be required if it is established that the bottom hole location or completion location is not a reasonable location.

(B) Directional surveys shall be required on each well drilled under the directional deviation provisions of this section.

(C) No oil, gas, or geothermal resource allowable shall be assigned any well on which a directional survey is required under any provision of this section until a directional survey has been filed with and accepted by the commission.

(2) Filing and type of survey.

(A) Directional surveys required under this section must be run by competent surveying companies, approved by the commission, signed and certified by a person having actual knowledge of the facts, in the manner prescribed by the commission in accordance with §3.12 of this title (relating to Directional Survey Company Report).

(B) All directional surveys, unless otherwise specified by the commission, shall be either single shot surveys or multi-shot surveys with the shot points not more than 200 feet apart, beginning within 200 feet of the surface, and the bottom hole location must be oriented both to the surface location and to the lease lines (or unit lines in cases of pooling).

(C) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth. However, if such method is used, the inclination drifts from the surface of the ground to the surface casing depth must be added cumulatively and reported on the appropriate form. This total shall be assumed to be in the direction least favorable to the operator, and such point shall be considered the starting point of the directional survey.

(d) Intentional deviation of wells.

(1) Definitions.

(A) Directional deviation--The intentional deviation of a well from vertical in a predetermined compass direction.

(B) Random deviation--The intentional deviation of a well without regard to compass direction for one of the following reasons:

(i) to straighten a hole which has become crooked in the normal course of drilling;

(ii) to sidetrack a portion of a hole because of mechanical difficulty in drilling.

(2) When permitted.

(A) Directional deviation. A permit for directionally deviating a well may be granted by the commission:

(i) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

(ii) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

(iii) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

(iv) where it can be shown to be advantageous from the standpoint of mechanical operation to drill more than one well from the same surface location to reach the productive horizon at essentially the same positions as would be reached if the several wells were normally drilled from regular locations prescribed by the well spacing rules in effect;

(v) for the purpose of drilling a horizontal drainhole; or

(vi) for other reasons found by the commission to be sufficient after notice and hearing.

(B) Random deviation. Permission for the random deviation of a well may be granted by the commission whenever the necessity for such deviation is shown, as prescribed in paragraph (3)(C) of this subsection.

(3) Applications for deviation.

(A) Applications for wells to be directionally deviated must specify on the application to drill both the surface location of the well and the projected bottom hole location of the well. On the plat, in addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the following shall be included:

(i) two perpendicular lines providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest points on the lease, pooled unit, or unitized tract line. If there is an unleased interest in a tract of the pooled unit or unitized tract that is nearer than the pooled unit or unitized tract line, the nearest point on that unleased tract boundary shall be used;

(ii) a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(iii) a line providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest oil, gas, or oil and gas well, identified by number, applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir; and

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottomhole location.

(B) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and upon giving such notice, the operator may proceed with the directional deviation. The commission may, at its discretion, accept written notice electronically transmitted. If the operator proceeds with the drilling of a deviated well under such circumstances, he proceeds at his own risk. Before any allowable shall be assigned to such well, a permit for the subsurface location of each completion interval shall be obtained from the commission under the provisions set out in the commission rules. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

(C) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this section on inclination surveys. The commission may, at its discretion, accept written notice electronically transmitted.

(e) Surveys on request of other operators. The commission, at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of survey approved by the commission for the purpose of determining bottom hole location of wells, shall be made in regard to a well complained of in the same field.

(1) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease lines.

(2) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by the commission as security against all costs and risks associated with the survey.

(3) The complaining party and the commission shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company on the commission's approved list.

(4) The survey shall be witnessed by the commission, and may be witnessed by any party, or his agent, who has an interest in the field.

(5) Nothing in these rules shall be construed to prevent

or limit the commission, acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with the commission rules and regulations.

(f) Penalties.

(1) False reports. The filing of a false or incorrect directional survey shall be grounds for cancellation of the well permit, for pipeline severance of the lease on which the well is located, for penalty action under the applicable statutes, and/or for such other and further action as may be appropriate.

(2) Other. The same penalties and actions as set forth in paragraph (1) of this subsection shall be assessable against any operator who refuses to comply with a commission order which issues under subsection (e) of this section.

Source Note: The provisions of this §3.11 adopted to be effective January 1, 1976; amended to be effective July 4, 1979, 4 TexReg 2197; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective June 11, 2001, 26 TexReg 4088.

§3.12 Directional Survey Company Report

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

(1) the name of the surveying company;

(2) the name of the individual performing the survey for the surveying company;

(3) the title or position the individual holds with the surveying company;

(4) the date on which the individual performed the survey;

(5) the type of survey conducted and whether the survey was multishot;

(6) a complete identification of the well, including the name of the operator of the well; the fee owner; the commission lease number, if assigned; the well number; the API number, and the drilling permit number, the land survey; the field name; and the county and state; and

(7) a notation that the survey was conducted from a depth of ____ feet to ____ feet.

(b) Each directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease lines (or unit lines in case of pooling) shall be mailed by registered, certified, or overnight mail direct to the commission in Austin by the surveying company making the survey. The surveying company may file electronically if the Commission has provided for such filing.

Source Note: The provisions of this §3.12 adopted to be effective January 1, 1976; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective October 27, 2008, 33 TexReg 8785.

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

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

(1) Intent. The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. In accordance with §3.17 of this title (relating to Pressure on Bradenhead), operators must notify the Commission of bradenhead pressure. The Commission will evaluate notices of bradenhead pressure on a case-by-case basis to determine further action and will provide guidance to assist operators in wellbore evaluation.

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

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar and/or float shoe is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--

(i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(ii) For intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or top of the highest proposed productive zone, whichever is less.

(C) Protection depth--Depth to which usable-quality

water must be protected, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

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

(E) Gas/oil contact zone--A zone in an oil well in which natural gas, commonly known as gas cap gas, overlies and is in contact with crude oil in a reservoir.

(F) Bay well--Any well under the jurisdiction of the Commission as defined in §3.78(a)(5) of this chapter.

(G) Deputy director of Field Operations--The deputy director of Field Operations of the Oil and Gas Division or the deputy director's delegate.

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

(I) District director--The Director of a Railroad Commission district office or the district director's delegate.

(J) Hydraulic fracturing treatment--A completion process involving treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas. The term does not include acid treatment, perforation, or other non-fracture treatment completion activities.

(K) Land well--Any well subject to Commission jurisdiction as defined in §3.78(a)(6) of this chapter.

(L) Minimum separation well--A well in which hydraulic fracturing treatments will be conducted and for which:

(i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet;

(ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or

(iii) the director has determined is in a structurally complex geologic setting.

(M) Offshore well--Any well subject to Commission jurisdiction as defined by §3.78(a)(7).

(N) Potential flow zone--A zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or oil, gas, or geothermal resources. The Commission will maintain a list of known zones by district and county that are considered potential flow zones and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(O) Zone with corrosive formation fluids--Any zone designated by the director or identified by the operator using available data containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field. The Commission will maintain a list of known zones by district and county that are considered zones with corrosive formation fluids, and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(P) Usable quality water--Water as defined in §3.30(e)(7)(B)(i) of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(3) Wellbore diameters.

(A) The diameter of the wellbore in which surface casing will be set and cemented shall be at least one and one-half (1.50) inches greater than the nominal outside diameter of casing to be installed, unless otherwise approved by the district director.

(B) For subsequent casing strings, the diameter of each section of the wellbore for which casing will be set and cemented shall be at least one (1) inch greater than the nominal outside diameter of the casing to be installed, unless otherwise approved by the district director. The district director may grant such approvals on an area basis.

(C) The casing diameter requirements in subparagraphs (A) and (B) of this paragraph do not apply to reentries, liners, and expandable casing.

(D) All float equipment, centralizers, packers, cement baskets, and all other equipment run into the wellbore on casing shall be consistent with the manufacturer's recommendations.

(4) Casing and cementing.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a

casing evaluation tool may be employed. Casing meeting the performance standards set forth in API Specification 5CT: Specification for Casing and Tubing (or a Commission-approved equivalent standard) shall be used through the protection depth.

(B) The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard).

(C) Casing shall be cemented across and above all formations permitted for injection under §3.9 of this title (relating to Disposal Wells) at the time the well is completed, or cemented immediately above all formations permitted for injection under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) at the time the well is completed, in a well within one-quarter mile of the proposed well location, as follows:

(i) if the top of cement is determined through calculation, at least 600 feet (measured depth) above the permitted formations;

(ii) if the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, 250 feet (measured depth) above the permitted formations;

(iii) if the top of cement is determined through the performance of a cement evaluation log, 100 feet (measured depth) above the permitted formations;

(iv) at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(D) Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, as follows:

(i) if the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the zones;

(ii) if the top of cement is determined through the performance of a temperature survey, across and extending 250 feet (measured depth) above the zones;

(iii) if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the zones;

(iv) across and extending at least 200 feet into the previous casing shoe (or to the surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(E) Where necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.

(5) Casing testing before drillout. For surface and intermediate strings of casing, before drilling the cement plug, the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot. The maximum test pressure required, however, unless otherwise ordered by the Commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation that the condition has been corrected. The operator shall notify the district director of a failed test. In the event of a pressure test failure, completion operations may not re-commence until the district director approves a remediation plan, the operator successfully implements the plan, and the operator conducts a successful pressure test.

(6) Well control.

(A) Wellhead assemblies. After setting the conductor pipe on offshore wells or surface casing on land or bay wells, wellhead assemblies shall be used on wells to maintain surface control of the well at all times. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(B) Well control equipment.

(i) An operator shall install a blowout preventer system or control head and other connections to keep the well under control at all times as soon as surface casing is set. When conductor casing is set and/or shallow gas is anticipated to be encountered, operators shall install a diverter system on the conductor casing. For bay and offshore wells, at a minimum, such systems shall include a double ram blowout preventer, including pipe and blind rams, an annular-type blowout preventer or other equivalent control system, and a shear ram.

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

(iii) Ram type blowout prevention equipment shall have a rated working pressure that equals or exceeds the maximum anticipated surface pressure of the well. Blowout preventer rams shall be of a proper size for the drill pipe being used or production casing being run in the well or shall be variable-type rams that are in the appropriate size range. Alternatively, an annular preventer may be used in lieu of casing/pipe rams or variable bore rams when running production casing provided the

expected shut-in surface pressures would not exceed the tested pressure rating of the annular preventer.

(iv) Operators shall install a drill pipe safety valve to prevent backflow of water, oil, gas, or other formation fluids into the drill string.

(v) Operators shall install a choke line of sufficient size and working pressure.

(vi) When using a Kelly rig during drilling, the well shall be fitted with an upper Kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower Kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(I) full-opening safety valve; and

(II) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(vii) All control equipment shall be consistent with API Standard 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. Control equipment shall be certified in accordance with API Standard 53 as operable under the product manufacturer's minimum operational specifications. Certification shall include the proper operation of the closing unit valving, the pressure gauges, and the manufacturer's recommended accumulator fluids. Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission.

(viii) All well control equipment shall be in good working condition at all times. All outlets, fittings, and connections on the casing, blowout preventers, choke manifold, and auxiliary wellhead equipment that may be subjected to wellhead pressure shall be of a material and construction to withstand or exceed the anticipated pressure. The lines from outlets on or below the blowout preventers shall be securely installed, anchored, and protected from damage.

(ix) In addition to the primary closing system, including an accumulator system, the blowout preventers shall have a secondary location for closure.

(x) Testing of blowout prevention equipment.

(I) Ram type blowout prevention equipment shall be tested to at least the maximum anticipated surface pressure of the well, but not less than 1,500 psi, before drilling the plug on the surface casing.

(II) Blowout prevention equipment shall be tested upon installation, after the disconnection or repair of any pressure containment seal in the blowout preventer stack, choke line, or choke manifold, limited to the affected component, with testing to occur at least every 21 days. When requested, the district director shall be notified before the commencement of a test.

(III) A record of each test, including test pressures, times, failures, and each mechanical test of the casings, blowout preventers, surface connections, surface fittings, and auxiliary wellhead equipment shall be entered in the logbook, signed by the person responsible for the test, and made available for inspection by the Commission upon request.

(C) Drilling fluid program.

(i) The characteristics, use, and testing of drilling fluid and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics shall be maintained. Drilling fluid tests shall be performed as needed to ensure well control. Adequate drilling fluid testing equipment shall be kept on the drilling location at all times. Sufficient drilling fluid shall be pumped and maintained to ensure well control at all times, including when pulling drill pipe. Mud pit levels shall be visually or mechanically monitored during the drilling process. Mud-gas separation equipment shall be installed and operated as needed when abnormally pressured gas-bearing formations may be encountered. The Commission shall have access to the drilling fluid records and shall be allowed to conduct any essential tests on the drilling fluid used in the drilling or recompletion of a well. When the conditions and tests indicate a need for a change in the drilling fluid program in order to insure control of the well, the operator shall use due diligence in modifying the program.

(ii) Wells drilled with air shall maintain well control using blowout preventer systems and/or diverter systems.

(iii) All hole intervals drilled prior to reaching the base of protected water shall be drilled with air, fresh water or a fresh water based drilling fluid. No oil-based drilling fluid may be used until casing has been set and cemented to the protection depth.

(D) Diverter systems for bay and offshore wells. Any bay or offshore well that is drilled to and/or through formations where the expected reservoir pressure exceeds the hydrostatic pressure of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. When the diverter system is installed, the diverter components including the sealing element, diverter valves, control systems, stations and vent lines shall be function and pressure tested. For drilling operations with a surface wellhead configuration, the system shall be function tested at least once every 24-hour period after the initial test. After all connections have been made on the surface casing or conductor casing, the diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psig. Subsequent pressure tests shall be conducted within seven days after the previous test. All diverter

systems shall be maintained in working condition. No operator shall continue drilling operations if a test or other information indicates that the diverter system is unable to function or operate as designed.

(E) Casinghead.

(i) Requirements. All land and bay wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves accessible at the surface, to allow pumping of fluid between any two strings of casing at the surface.

(ii) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the next casing string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. The casing shall be condemned if the pressure gauge on the casinghead reflects the applied pressure. After completing corrective measures, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot otherwise be determined.

(F) Christmas tree.

(i) All completed non-pumping wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(ii) The Christmas tree for completed bay and offshore wells shall be equipped with either two master valves, one master valve and one wing valve, or two wing valves. All bay and offshore wells shall have at least five feet of spacing between the bottom of the Christmas tree and the surface of the water at high tide, where applicable. Any newly completed bay and offshore well or existing well on which the Christmas tree is being replaced shall be equipped with a back pressure valve wellhead profile at the flange where the tubing hangs on the Christmas tree.

(G) Storm choke and safety valve.

(i) Bay and offshore wells shall be equipped with a storm choke and/or safety valve installed in the tubing.

(ii) An operator may request approval to use a surface safety valve in lieu of a subsurface safety valve by filing with the appropriate district director a written request for such approval providing all pertinent information to support the exception.

(iii) The depth and type of the safety valve shall be reported in the "remarks" section of the appropriate completion report form required by §3.16 of this title (relating to Log and Completion or Plugging Report), after the well is completed or recompleted.

(7) Additional requirements for wells on which hydraulic fracturing treatments will be conducted.

(A) All casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or fracture tubing may be subjected.

(B) The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. A surface pressure loss of greater than 10 percent of the initial test pressure is considered a failed test. The casing required to be pressure tested shall be from the wellhead to at least the depth of the top of cement behind the casing being tested. The district director shall be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(C) During hydraulic fracturing treatment operations, the operator shall monitor all annuli. The operator shall immediately suspend hydraulic fracturing treatment operations if the pressures deviates above those anticipated increases caused by pressure or thermal transfer and shall notify the appropriate district director within 24 hours of such deviation. Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director:

(i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).

(ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation

plan and successfully re-tested the casing (or fracture tubing).

(iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.

(iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

(I) successfully set, cemented, and tested the casing for which the exemption is requested in at least five minimum separation wells by the same operator in the same operating field;

(II) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results or other tests demonstrating that successful cement placement was achieved to isolate productive zones, potential flow zones, and/or zones with corrosive formation fluids; and

(III) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the five wells that have had successful cement jobs.

(8) Pipeline shut-off valves for bay and offshore wells. All bay and offshore gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment shall be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training for bay and offshore wells. All tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to, upon request, furnish certification of satisfactory completion of an American Petroleum Institute (API) training program, an International Association of Drilling Contractors (IADC) training program, or other equivalent nationally recognized training program on well control equipment and procedures. The certification shall be renewed every two years by attending an API- or IADC-approved refresher course or a refresher course approved by the equivalent nationally recognized training program.

(10) Bottom-hole pressure surveys. The Commission may require bottom-hole pressure surveys of the various fields at such times as determined to be necessary. However, operators shall be required to take bottom-hole pressures only in those wells that are not likely to suffer damaging effects from the survey. Tubing and tubingheads shall be free from obstructions in wells used for bottom-hole pressure test purposes.

(b) Casing and cementing requirements for land wells and bay wells.

(1) Surface casing requirements for land wells and bay wells.

(A) Any proposal to set surface casing to a depth of 3,500 feet or greater shall require prior approval of the appropriate district director. A request for such approval shall be in writing and shall specify how the operator plans to maintain well control during drilling, and ensure successful circulation and adequate bonding of cement, and, if necessary, prevent upward migration of deeper formation fluids into protected water. The district director may grant approvals on an area basis.

(B) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(C) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or the operator's representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(D) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement.

(iv) The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well.

(E) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(F) Cementing report. Within 30 days of completion of the well, or within 90 days of cessation of drilling operations, whichever is earlier, a cementing report must be filed with the Commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the Commission. The operator of the well or the operator's duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the Commission.

(G) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice for Centralizer Placement and Stop Collar Testing.

(H) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be considered on an individual well basis only. The district director may approve, modify, or reject the proposed program. The district director shall deny the request if the operator has not demonstrated that the alternative casing plan will achieve the intent of this rule as described in subsection (a)(1) of this section. If the proposal is modified or rejected, the operator may request a review by the deputy director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 100 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If

cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or the operator's representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the Commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(I) Mechanical integrity test of surface casing after drillout.

(i) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director.

(ii) If a mechanical integrity test is conducted, the appropriate district office shall be notified at least eight hours before the test is conducted to give the district office an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. The appropriate district office shall be notified within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.

(2) Intermediate casing requirements for land wells and bay wells.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented;

(i) if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(ii) if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(iii) if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or

(iv) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(B) Top of cement. The calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title (relating to Log and Completion or Plugging Report).

(C) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone, and/or zone with corrosive formation fluids make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively isolate and seal the zones to prevent fluid migration to or from such strata within the wellbore.

(3) Production casing requirements for land wells and bay wells.

(A) Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.

(B) Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the Commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive zone, potential flow zone and/or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating casing pressure tests. In the event that the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone and/or zone with corrosive formation fluids make cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such zones, and prevent fluid migration to or from such zones within the wellbore.

Uncemented casing is allowable within a producing reservoir provided the production casing is cemented in such a manner to effectively isolate and seal off that zone from all other productive zones in the wellbore as required by §3.7 of this title (relating to Strata To Be Sealed Off).

(C) Reporting of top of cement. Calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title.

(D) Isolation of gas/oil contact zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(4) Tubing requirements for land wells and bay wells.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet (vertical depth) above the top of the producing interval nor more than 50 feet (vertical depth) above the top of the liner, if a liner is used, or 100 feet (vertical depth) above the kickoff point in a deviated or horizontal well. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet (vertical depth) above the top of the perforated or open-hole interval actually open for production into the wellbore.

(B) Alternate tubing requirements. Alternate programs requesting a temporary exception pursuant to subsection (d) of this section to omit tubing from a flowing oil well may be authorized on an individual well basis by the appropriate district director. The district director shall deny the request if the operator has not demonstrated that the alternative tubing plan will achieve the intent as described in subsection (a)(1) of this section. If the proposal is rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a hearing. An operator shall obtain approval of any alternative program before commencing operations.

(c) Casing, cementing, drilling, and completion requirements for offshore wells.

(1) Casing. An offshore well shall be cased with at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	**Surface**
to 7,000 feet	25% of proposed total depth of well
7,000 - 10,000 feet	2,000 feet
10,000 and below	2,500 feet

(ii) Surface Casing test.

(I) Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes constitutes confirmation that the condition has been corrected.

(II) After drillout, if the surface casing is exposed to more than 360 rotating hours, the operator shall verify the integrity of the casing using a casing evaluation tool, a mechanical integrity test, or an equivalent Commission-approved alternate casing evaluation methodology, unless otherwise approved by the district director.

(III) If a mechanical integrity test of the surface casing is conducted, the appropriate district office shall be notified a minimum of eight (8) hours before the test is conducted. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a minimum test pressure of 0.5 psi per

foot multiplied by the true vertical depth of the surface casing up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% drop in pressure after 30 minutes constitutes confirmation of an acceptable pressure test. The operator shall notify the appropriate district office within 24 hours of a failed test. Operations may not re-commence until the district director approves a remediation plan and the operator implements the approved plan, and the operator successfully re-tests the surface casing.

(C) Production casing or oil string.

(i) The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure.

(ii) After cementing, the production casing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner.

(iii) Cementing of the production casing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zones, potential flow zones, or zones with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Operators shall comply with the well control requirements of subsection (a)(6) of this section.

(d) Exceptions or alternate programs. The director may administratively grant an exception or approve an alternate casing/tubing program required by this section provided that the alternate casing/tubing program will achieve the intent of the rule as described in subsection (a)(1) of this section and the following requirements are met:

(1) The request for an exception or alternate casing/tubing program shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception for tubing shall not exceed a period of 180 days. A request for an exception for tubing beyond 180 days shall require a Commission order.

Source Note: The provisions of this §3.13 adopted to be effective January 1, 1976; amended to be effective April 8, 1980, 5 TexReg 1152; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective January 1, 1983, 7 TexReg 3982; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective January 11, 1991, 16 TexReg 39; amended to be effective August 13, 1991, 16 TexReg 4153; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.14 Plugging

(a) Definitions and application to plug.

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

(A) Approved cementer--A cementing company, service company, or operator approved by the Commission or its delegate to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission or its delegate to use an alternate material other than cement to plug a well.

(B) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(C) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(D) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter that has been completed, signed, and filed with the Commission or its delegate.

(E) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(F) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(G) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission or its delegate on Form PR, Monthly Production Report.

(H) Serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is

absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(I) Usable quality water strata--All strata determined by the Groundwater Advisory Unit of the Oil and Gas Division to contain usable quality water.

(J) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on Commission Form P-13, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party

cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed unless the Commission or its delegate approves a plugging extension under §3.15 of this title (relating to Surface Equipment Removal Requirements and Inactive Wells).

(3) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil, gas, or other formation fluid is leaking from the well, and:

(i) neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) the Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) the well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(4) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (3) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata. Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division. The operator shall verify the placement of the plug required at the base of the deepest usable quality water stratum by tagging with tubing or drill pipe or by an alternate method approved by the district director or the district director's delegate.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present. An operator shall request approval to use alternate materials, other than API oil well cement without volume extenders, to plug a well by filing with the director or the director's delegate a written request

providing all pertinent information to support the use of the proposed alternate material and plugging method. The director or the director's delegate shall determine whether such a request warrants approval, after considering factors which include but are not limited to whether or not the well to be plugged was used as an injection or disposal well; the well's history; the well's current bottom hole pressure; the presence of highly pressurized formations intersected by the wellbore; the method by which the alternative material will be placed in the wellbore; and the compressive strength and other performance specifications of the alternative material to be used. The director or the director's delegate shall approve such a request only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

(5) Operators shall use only cementers approved by the director or the director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement or other alternate materials as approved by the director or the director's delegate; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement or other alternate materials as approved by the director or the director's delegate; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement or other alternate materials as approved by the director or the director's delegate according to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the director or the director's delegate recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the director or the director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the director or the director's delegate for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written request with the district director and demonstrate its ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this subsection. The district director or the director's delegate shall determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director or the director's delegate may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the director or the director's delegate. The hole shall be in static condition at the time the cement plugs are placed. The district director

or the director's delegate may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources. An operator shall request approval to use alternate fluid other than mud-laden fluid by filing with the district director a written request providing all pertinent information to support the use of the proposed alternate fluid. The district director or the director's delegate shall determine whether such a request warrants approval, and shall approve such a request only if the proposed alternate fluid will insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §4.614(b) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Authorized Disposal Methods, respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director or the director's delegate.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of §3.8 of this title (relating to Water Protection (Statewide Rule 8)). The district director or the director's delegate may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and 50 feet below the base of the deepest usable quality water stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug shall be set across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(4) Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(5) An operator may not remove, cause to be removed, or allow to be removed surface casing from a well at abandonment. This prohibition applies to wells drilled by cable tool and rotary rigs alike.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the base of the deepest usable quality water stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(2) For wells in which the production casing has not

been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director or the director's delegate may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(4) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the screen or liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director or the director's delegate shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director or the director's delegate may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director or the director's delegate. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

Source Note: The provisions of this §3.14 adopted to be effective January 1, 1976; amended to be effective February 29, 1980, 5 TexReg 499; amended to be effective January 1, 1983, 7 TexReg 3989; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective September 8, 1986, 11 TexReg 3792; amended to be effective November 9, 1987, 12 TexReg 3959; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective March 1, 1992, 17 TexReg 1227; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective September 20, 1995, 20 TexReg 6931; amended to be effective September 14, 1998, 23 TexReg 9300; amended to be effective December 28, 1999, 24 TexReg 11711;amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective July 28, 2003, 28 TexReg 5853; amended to be effective December 3, 2003, 28 TexReg 10747; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.15 Surface Equipment Removal Requirements and Inactive Wells

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

(1) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or until the well has reported production of at least one barrel of oil for oil wells or at least one Mcf of gas for gas wells each month for 12 consecutive months.

(2) Cost calculation for plugging an inactive well--The cost, calculated by the Commission or its delegate, for each foot of well depth plugged based on average actual plugging costs for wells plugged by the Commission for the preceding state fiscal year for the Commission Oil and Gas Division district in which the inactive well is located.

(3) Delinquent inactive well--An inactive well for which, after notice and opportunity for a hearing, the Commission or its delegate has not extended the plugging deadline.

(4) Enhanced oil recovery (EOR) project--A project that does not include a water disposal project and is:

(A) a Commission-approved EOR project that uses any process for the displacement of oil or other hydrocarbons from a reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process;

(B) a certified project described by Texas Tax Code, §202.054; or

(C) any other project approved by the Commission or its delegate for EOR.

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

(6) Inactive well--An unplugged well that has been spudded or has been equipped with cemented casing and that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.

(7) Operator designation form--A certificate of compliance and transportation authority or an application to drill, recomplete, and reenter that has been approved by the Commission or its delegate.

(8) Physical termination of electric service to the well's production site--Disconnection of the electric service to an inactive well site at a point on the electric service lines most distant from the production site toward the main supply line in a manner that will not interfere with electrical supply to adjacent operations, including cathodic protection units.

(b) Plugging of inactive bay and offshore wells required.

(1) An operator of an existing inactive bay or offshore well as defined in §3.78 of this title (relating to Fees and Financial Security Requirements) must:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive bay or offshore well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive bay or offshore well if the plugging of the well is otherwise required by Commission rules or orders.

(c) Extension of deadline for plugging an inactive bay or offshore well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive bay or offshore well as defined by Commission rules if:

(1) the operator has a current organization report;

(2) the operator has, and on request provides, evidence of a good faith claim to a continuing right to operate the well;

(3) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(4) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(d) Plugging of inactive land wells required.

(1) An operator that assumes responsibility for the physical operation and control of an existing inactive land well must maintain the well and all associated facilities in compliance with all applicable Commission rules and orders and within six months after the date the Commission or its delegate approves an operator designation form must either:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive land well if the plugging of the well is otherwise required by Commission rules or orders.

(3) Except for an operator designation form filed for the purpose of a name change, the Commission or its delegate may not approve an operator designation form for an inactive land well until the operator satisfies the requirements of paragraph (1)(C) of this subsection.

(4) If an operator fails to restore the well to active operation as defined by Commission rule, plug the well in compliance with a Commission rule or order, or obtain an extension of the deadline for plugging an inactive well within six months after acquiring an inactive well, the

Commission or its delegate may, after notice and opportunity for hearing, revoke the operator's organization report.

(5) The Commission or its delegate may approve an organization report that is delinquent or has been revoked if the Commission or its delegate simultaneously approves extensions of the deadline for plugging the operator's inactive wells.

(e) Extension of deadline for plugging an inactive land well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive land well if:

(1) the Commission or its delegate approves the operator's Application for an Extension of Deadline for Plugging an Inactive Well (Commission Form W-3X);

(2) the operator has a current organization report;

(3) the operator has, and on request provides evidence of, a good faith claim to a continuing right to operate the well;

(4) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(5) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(f) Application for an extension of deadline for plugging an inactive land well.

(1) This subsection does not apply to a bay well or an offshore well as those terms are defined in §3.78 of this title.

(2) An operator must include the following in an application for an extension of the deadline for plugging an inactive well:

(A) an affirmation made by an individual with personal knowledge of the physical condition of the inactive well pursuant to the provisions of Texas Natural Resources Code, §91.143, stating the following: that the operator has physically terminated electric service to the well's production site; and either:

(i) if the operator does not own the surface of the land where the well is located and the well has been inactive for at least five years but for less than 10 years as of the date of renewal of the operator's organization report, that the operator has emptied or purged of production fluids all piping, tanks, vessels, and equipment associated with and exclusive to the well; or

(ii) if the operator does not own the surface of the land where the well is located, and the well has been inactive for at least 10 years as of the date of renewal of the operator's organization report, that the operator has removed all surface equipment and related piping, tanks, tank batteries, pump jacks, headers, fences, and firewalls; has closed all open pits; and has removed all junk and trash, as defined by Commission rule, associated with and exclusive to the well; and

(B) documentation that the operator has satisfied at least one of the following requirements:

(i) for all inactive land wells that an operator has operated for more than 12 months, the operator has plugged or restored to active operation, as defined by Commission rule, 10% of the number of inactive land wells operated at the time of the last annual renewal of the operator's organization report;

(ii) if the operator is a publicly traded entity, for all inactive land wells, the operator has filed with the Commission a copy of the operator's federal documents filed to comply with Financial Accounting Standards Board Statement No. 143, Accounting for Asset Retirement Obligations, and an original executed Uniform Commercial Code Form 1 Financing Statement, filed with the Secretary of State, that names the operator as the "debtor" and the Railroad Commission of Texas as the "secured creditor" and specifies the funds covered by the documents in the amount of the cost calculation for plugging all inactive wells;

(iii) the filing of a blanket bond on Commission Form P-5PB(2), Blanket Performance Bond, a letter of credit on Commission Form P-5LC, Irrevocable Documentary Blanket Letter of Credit, or a cash deposit, in the amount of either the lesser of the cost calculation for plugging all inactive wells or $2 million;

(iv) for each inactive land well identified in the application, the Commission has approved an abeyance of plugging report and the operator has paid the required filing fee;

(v) for each inactive land well identified in the application, the operator has filed a statement that the well is part of a Commission-approved EOR project;

(vi) for each inactive land well identified in the application that is not otherwise required by Commission rule or order to conduct a fluid level or hydraulic pressure test of the well, the operator has conducted a successful fluid level test or hydraulic pressure test of the well and the operator has paid the required filing fee;

(vii) for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved a supplemental bond, letter of credit, or cash deposit in an amount at least equal to the cost calculation for plugging an inactive land well for each well specified in the application; or

(viii) for each time an operator files an application for a plugging extension and for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved an escrow fund deposit in an amount at least equal to 10% of the total cost calculation for plugging an inactive land well.

(g) Commission action on application for plugging extension.

(1) The Commission or its delegate shall administratively grant all applications for plugging extensions that meet the requirements of Commission rules.

(2) The Commission or its delegate may administratively deny an application for a plugging extension for an inactive well if the Commission or its delegate determines that:

(A) the applicant does not have an active organization report at the time the plugging extension application is filed;

(B) the applicant has not submitted all required filing fees and financial assurance for the requested plugging extension and for renewal of its organization report; or

(C) the applicant has not submitted a signed organization report for the applied-for extension year that qualifies for approval regardless of whether the applicant has complied with the inactive well requirements of this section.

(3) Except as provided in paragraph (2) of this subsection, if the Commission or its delegate determines that an organization report should be denied renewal solely because it does not meet the inactive well requirements of this section, a Commission delegate shall, within a reasonable time of not more than 14 days after receipt of the applicant's administratively complete organization report renewal packet, including all statutorily required fees and financial assurance:

(A) notify the operator of the determination;

(B) provide the operator with a written statement of the reasons for the determination; and

(C) notify the operator that it has 90 days from the expiration of its most recently approved organization report to comply with the requirements of this section.

(4) If, after the expiration of the 90-day period specified in paragraph (3)(C) of this subsection, the Commission or its delegate determines that the operator remains out of compliance with the requirements of this section, the Commission delegate shall mail the operator a written notice of this determination. The operator may request a hearing. If the operator fails to timely file a request for hearing and the required hearing fee, the Commission shall enter an order denying the plugging extension request and denying renewal of the operator's organization report without further notice or opportunity for hearing.

(5) To request a hearing, the operator must file a written request for hearing and the hearing fee of $4,500 with the Hearings Division, no later than 30 days from the date the written notice was mailed to the operator. In the request for hearing, the operator must identify by its assigned American Petroleum Institute (API) number each inactive well for which the operator is seeking a hearing to contest the determination that the well remains out of compliance. At the time an operator files a request for hearing under this subsection, the operator shall provide a list of affected persons to be given notice of the hearing. Affected persons shall include the owners of the surface estate of each tract on which a well that is the subject of the hearing request is located, the director of the Commission's Enforcement Section, and the district director of each Commission district in which the wells are located. The applicant's failure to diligently prosecute a hearing requested under this subsection may result in the application being involuntarily dismissed for want of prosecution on the motion of any affected person or on the Commission's own motion.

(6) If an operator files a timely plugging extension application that is not properly administratively denied for the reasons specified in paragraph (2) of this subsection, then the operator's previously approved organization report shall remain in effect until the Commission approves its plugging extension application or enters a final order denying the application.

(h) Revocation of extension. The Commission or its delegate may revoke an extension of the deadline for plugging an inactive well if the Commission or its delegate determines, after notice and an opportunity for a hearing, that the applicant is ineligible for the extension under the Commission's rules or orders.

(i) Removal of surface equipment for land wells inactive more than 10 years. Requirements to remove surface equipment for land wells inactive more than 10 years do not excuse an operator from compliance with all other applicable Commission rules and orders including the requirements in Chapter 4 of this title (relating to Environmental Protection).

(1) An operator of an inactive land well must leave a clearly visible sign as required by §3.3 of this title (relating to Identification of Properties, Wells, and Tanks) at the wellhead of the well and must maintain wellhead control as required by §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements).

(2) An operator may not store surface equipment removed from an inactive land well on an active lease.

(3) An operator may be eligible for a temporary extension of the deadline for plugging an inactive land well or a temporary exemption from the surface equipment

removal requirements if the operator is unable to comply with the requirements of subsection (f)(2)(A) of this section because of safety concerns or required maintenance of the well site and the operator includes with the application a written affirmation of the facts regarding the safety concerns or maintenance.

(4) An operator may be eligible for an extension of the deadline for plugging a well without complying with the surface equipment removal requirements for inactive land wells if the well is located on a unit or lease or in a field associated with an EOR project and the operator includes a statement in the written affirmation that the well is part of such a project. The exemption provided by this subsection applies only to the equipment associated with current and future operations of the project.

(j) Abeyance of plugging report.

(1) An operator that files an abeyance of plugging report must:

(A) pay an annual fee of $100 for each inactive land well covered by the report;

(B) use Commission Form W-3X on which the operator must specify the field and the covered wells within that field; and

(C) for each well, include a certification signed and sealed by a person licensed by the Texas Board of Professional Engineers or the Texas Board of Professional Geoscientists stating that the well has:

(i) a reasonable expectation of economic value in excess of the cost of plugging the well for the duration of the period covered by the report, based on the cost calculation for plugging an inactive well;

(ii) a reasonable expectation of being restored to a beneficial use that will prevent waste of oil or gas resources that otherwise would not be produced if the well were plugged; and

(iii) documentation demonstrating the basis for the affirmation of the well's future utility.

(2) Except as provided in paragraph (3) of this subsection, the Commission or its delegate may not transfer an abeyance of plugging report to a new operator of an existing inactive land well. The new operator of an existing inactive land well must file a new abeyance of plugging report or otherwise comply with the requirements of this subchapter not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer an abeyance of plugging report in the event of a change of name of an operator.

(k) Enhanced oil recovery (EOR) project.

(1) An inactive well is considered to be part of an EOR project if the well is located on a unit or lease or in a field associated with a Commission-approved EOR project.

(2) Except as provided in paragraph (3) of this subsection, the Commission and its delegate may not transfer a statement that an inactive well is part of an EOR project to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new statement stating that the well is part of such an EOR project or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer a statement that a well is part of an EOR project in the event of a change of name of an operator.

(l) Fluid level or hydraulic pressure test for inactive wells more than 25 years old.

(1) At least three days prior to the test, the operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) For each inactive well that is more than 25 years old and that has been inactive more than 10 years, the operator must perform either a fluid level test once every 12 months or a hydraulic pressure test once every five years and obtain the approval of the Commission or its delegate of the results of said tests.

(4) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file

the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) An operator of an inactive well that is more than 25 years old may not return that inactive well to active operation unless the operator performs either a successful fluid level test of the well within 12 months prior to the return to activity or a successful hydraulic pressure test of the well within five years prior to the return to activity.

(m) Fluid level or hydraulic pressure test for inactive land well less than 25 years old.

(1) At least three days prior to the test, each operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(4) An operator that files documentation of a fluid level test or a hydraulic pressure test for an inactive land well less than 25 years old in order to obtain a plugging extension must pay an annual fee of $50 for each well covered by the documentation.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) The Commission or its delegate may transfer documentation of the results of a fluid level or hydraulic pressure test to a new operator of an existing inactive land well that is less than 25 years old.

(n) Supplemental financial assurance.

(1) A supplemental bond, letter of credit, or cash deposit filed as part of an application for an extension for an inactive land well is in addition to any other financial assurance otherwise required of the operator or for the well.

(2) The Commission or its delegate may not transfer a supplemental bond, letter of credit, or cash deposit to a new operator of an existing inactive land well. A new operator of an existing inactive land well must file a new supplemental bond, letter of credit, or cash deposit or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves an operator designation form.

(o) Escrow funds.

(1) An operator must deposit escrow funds with the Commission each time the operator files an application for an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may release escrow funds deposited with the Commission only as prescribed by §3.78 of this title.

(p) Plugging more than 10% of inactive well inventory. If an operator plugs more than 10% of the number of inactive land wells during a 12-month organization report cycle, the Commission will count the number of plugged wells above 10% toward fulfillment of the 10% blanket option under subsection (f)(2)(B)(i) of this section during the next organization report cycle.

Source Note: The provisions of this §3.15 adopted to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 15, 2011, 36 TexReg 5096; amended to be effective July 2, 2012, 37 TexReg 4894; amended to be effective January 1, 2017, 41 TexReg 9465.

§3.16 Log and Completion or Plugging Report

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

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

(2) Drilling operation--A continuous effort to drill or deepen a wellbore for which the commission has issued a permit.

(3) Operator--A person who assumes responsibility for the regulatory compliance of a well as shown by a form the person files with the commission and the commission approves.

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

(b) Completion and plugging reports.

(1) The operator of a well shall file with the commission the appropriate completion report within 90 days after completion of the well or within 150 days after the date on which the drilling operation is completed, whichever is earlier.

(2) The operator of a well shall file with the Commission an amended completion report within 30 days of any physical changes made to the well, such as any change in perforations, or openhole or casing records.

(3) If the well is a dry hole, the operator shall file with the commission an appropriate plugging report within 30 days after the well is plugged.

(c) Electric logs. Except as otherwise provided in this section, not later than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a legible and unaltered copy of an electric log, except that where a well is deepened, a legible and unaltered copy of an electric log shall be filed if such log is run over a deeper interval than the interval covered by an electric log for the well already on file with the commission. In the event an electric log, as defined in this section, has not been run, subject to the commission's approval, the operator shall file a lithology log or gamma ray log of the entire wellbore. In the event no log has been run over the entire wellbore, subject to the commission's approval, the operator shall file the log which is the most nearly complete of the logs run. An electric log shall be filed with the commission electronically in a digital format acceptable to the commission, when the commission has the technological capability to receive the electronic filing. Nothing in this subsection requires an operator to run an electric log in conjunction with the drilling or deepening of a well.

(d) Delayed filing based on confidentiality. Each log filed with the commission shall be considered public information and shall be available to the public during normal business hours. If the operator of a well desires a log to be confidential, on or before the 90th day after the date a drilling operation is completed, the operator must submit to the Oil and Gas Division in Austin a written request for a delayed filing of the log. If a well is drilled on land submerged in state water, when filing such a request, the operator must retain the log and may delay filing such log for five years beginning from the date the drilling operation was completed. For any other well, the operator must retain the log and may delay filing such log for three years beginning from the date the drilling operation was completed. Logs must be filed with the commission within 30 days after the expiration of the confidentiality period.

(e) Sanctions. If an operator fails to file a completion report or log in accordance with the provisions of this section, the commission may refuse to assign an allowable to a well, set the allowable for such well at zero, and/or initiate penalty action pursuant to the Texas Natural Resources Code, Title 3.

Source Note: The provisions of this §3.16 adopted to be effective January 1, 1976; amended to be effective February 20, 1986, 11 TexReg 545; amended to be effective January 30, 2006, 31 TexReg 477; amended to be effective April 28, 2015, 40 TexReg 2273; amended to be effective February 23, 2016, 41 TexReg 1226.

§3.17 Pressure on Bradenhead

(a) All wells shall be equipped with a Bradenhead. Whenever pressure develops between any two strings of casing, the district office shall be notified immediately. No cement may be pumped between any two strings or pipe at the top of the hole, except after permission has been granted by the district office.

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

Source Note: The provisions of this §3.17 adopted to be effective January 1, 1976.

§3.18 Mud Circulation Required

When coming out of the hole with the drill pipe, drilling fluid shall be circulated until equalized, and a fill-up line shall be turned into the casing to insure a full load of fluid on the bottom of the hole at all times.

Source Note: The provisions of this §3.18 adopted to be effective January 1, 1976.

§3.19 Density of Mud-Fluid

In cable tool drilling, no operator shall drill into a known oil, gas, or geothermal resource producing formation with water from a higher formation in the hole, or with a sufficient head of water introduced into the hole to prevent gas blowing to the surface. The well shall either be allowed to blow until it has been drilled-in or it shall be drilled under a head of fluid whose weight shall average not less than 9 1/2 pounds per gallon; but in no case shall gas be allowed to blow for a longer period than three days after completion of the well. Mud-laden fluid used for protecting oil, gas, or geothermal resource bearing sands in upper formations while oil, gas, or geothermal resource is being produced from deeper formations shall have an average weight of not less than 91 pounds per gallon.

Source Note: The provisions of this §3.19 adopted to be effective January 1, 1976.

§3.20 Notification of Fire Breaks, Leaks, or Blow-outs

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

§3.21 Fire Prevention and Swabbing

(a) No hydrocarbon flow tank, unless entirely buried, shall hereafter be placed nearer than 150 feet from any derrick, rig, building, power plant, or boiler of any description. The director of the Oil and Gas Division or his delegate may administratively grant exceptions to this requirement. If the director of the Oil and Gas Division declines to administratively grant, continue, or extend an exception, the operator shall move the hydrocarbon flow tank to the required distance or request a hearing on the matter. After hearing, the examiner shall recommend final action to the commission.

(b) No field working hydrocarbon tank having a capacity of 10,000 barrels or more shall be built nearer than 200 feet (measured from shell to shell) to any other like tank.

(c) No person engaged in the production, transportation, storage, handling, refining, reclaiming, processing, treating, or marketing of crude petroleum oil or the products or by-products thereof shall store, either permanently or temporarily, crude petroleum oil or the products and by-products thereof in open pits or earthen storage.

(d) All oil tanks where there is a gas hazard shall be gas tight and provided with proper gas vents.

(e) No forge or open light shall be placed inside the derrick of a well showing oil or gas.

(f) Boilers must be equipped with steam lines for fighting fire and must not be set nearer than 150 feet to any producing well.

(g) All wells shall be cleaned into a pit not less than 40 feet from the derrick floor and 150 feet from any fire hazard.

(h) No boiler or electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank.

(i) Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of any well, tank, or pump station. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

(j) Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks, that are within the corporate limits of any city, town, or village; or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1,000 feet to any school or church; or where such tanks are so located as to be deemed by the commission to be an objectionable hazard.

(k) Swabbing, bailing, or air jetting of wells is prohibited as a production method for wells unless the Commission has, after notice and hearing, granted an exception to this subsection. The Commission shall give notice of the hearing at least 10 days prior to the date of the hearing.

(1) An operator seeking an exception to allow swabbing, bailing, or air jetting of a well shall:

(A) provide the Commission with the names and mailing addresses of the mineral interest owners of record and surface owners of record of the lease on which a well for which an exception is sought is located;

(B) present evidence at the hearing establishing:

(i) the method of production proposed;

(ii) that any production is properly accounted for pursuant to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil);

(iii) that the proposed exception is necessary to prevent waste or protect correlative rights;

(iv) that wellhead control is sufficient to prevent releases from the well;

(v) that no pollution of usable quality water or safety hazard will result from either the proposed production method or the condition of the well; and

(vi) that the operator possesses a continuing good faith claim to the right to operate the well.

(2) In addition to the information set out in paragraph (1) of this subsection, factors that the Commission may consider in ruling on a request for an exception include:

(A) whether the well has passed a mechanical integrity test within the preceding 12 months;

(B) the estimated monthly and cumulative production from the well if the requested exception is granted;

(C) whether production will be into an on-lease tank battery or a mobile tank;

(D) the adequacy of the financial assurance provided by the operator to assure that the well will be timely and properly plugged;

(E) whether production volume, fine sands in the reservoir, or other factors render pumping of the well impracticable;

(F) whether the reservoir from which the well produces contains hydrogen sulfide; and

(G) the operator's history of compliance with Commission rules.

(3) This section does not prohibit swabbing as a non-recurring method to start initial production, to test or clean out a well, or to restore a well to flowing or pumping status.

(l) Operation and maintenance of electrical power lines. An operator must construct, operate, and maintain an electrical power line serving a well site or other surface facility employed in operations incident to oil and gas development and production in accordance with the National Electrical Code published by the National Fire Protection Association and adopted by the Texas Department of Licensing and Regulation in §73.100 of this title (relating to Technical Requirements).

Source Note: The provisions of this §3.21 adopted to be effective January 1, 1976, amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective October 2, 2002, 27 TexReg 9149; amended to be effective September 13, 2010, 35 TexReg 8332.

§3.22 Protection of Birds

(a) If an operator who maintains a tank or pit does not take protective measures necessary to prevent harm to birds, the operator may incur liability under federal and state wildlife protection laws. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties

for the death of certain species of birds due to contact with oil in a tank or pit. These penalties may include imprisonment. State statutes also protect certain species of birds. The Railroad Commission of Texas (commission) is cooperating with federal and state wildlife authorities in their efforts to protect birds.

(b) An operator must screen, net, cover, or otherwise render harmless to birds the following categories of open-top tanks and pits associated with the exploration, development, and production of oil and gas, including transportation of oil and gas by pipeline:

(1) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of oil; however, temporary, portable storage tanks that are used to hold fluids during drilling operations, workovers, or well tests are exempt;

(2) skimming pits as defined in §3.8 of this title (relating to Water Protection) (Statewide Rule 8); and

(3) collecting pits as defined in §3.8 of this title (relating to Water Protection) that are used as skimming pits.

(c) If the commission finds a surface film or accumulation of oil in any other pit regulated under §3.8 of this title (relating to Water Protection), the commission will instruct the operator to remove the oil. If the operator fails to remove the oil from the pit in accordance with the commission's instructions or if the commission finds a surface film or accumulation of oil in the pit again within a 12-month period, the commission will require the operator to screen, net, cover, or otherwise render the pit harmless to birds. Before complying with this requirement, the operator will have a right to a hearing upon request. In addition to the enforcement actions specified by this subsection, the commission may take any other appropriate enforcement actions within its authority.

Source Note: The provisions of this §3.22 adopted to be effective September 1, 1991, 16 TexReg 2523; amended to be effective November 1, 1991, 16 TexReg 4737.

§3.23 Vacuum Pumps

The installation of a vacuum pump or other device for the purpose of putting vacuum on any gas or oil-bearing formation, or the application of any vacuum to any gas or oil-bearing formation is prohibited, except as follows.

(1) If casinghead gas is utilized in a casinghead-gas plant, vacuum may be used, but no more than is sufficient to gather the gas and deliver it at the plant. In no event shall more than two points of vacuum (two inches of mercury) be used at the casinghead.

(2) In a field which is depleted or practically depleted vacuum may be used, but no vacuum pump shall be installed or used without a permit from the commission obtained upon application after notice to adjacent lease owners and operators and a public hearing on such application.

Source Note: The provisions of this §3.23 adopted to be effective January 1, 1976.

§3.24 Check Valves Required

(a) Where two or more wells are being produced through a common line, a common separator, or a common manifold, the flow lines leading from each well to such common line, common separator, or common manifold shall be equipped with a check valve or other means of shut-off which shall at all times be kept in good working order. The check valve or other means of shut-off shall be placed in each flow line above the surface of the ground and shall be located in the flow line as close to the wellhead connection as is practicable. Where a manifold system is employed in which each well produced through the manifold system has its own individual flow line leading from the wellhead to the manifold, then it shall be permissible for the check valve or other means of shut-off to be placed in the flow line near a point where the flow line enters the manifold system. The check valve or other means of shut-off must be above ground, and must be in the flow line serving the well and must be located between the wellhead and the point where the flow line connects with any other flow line, common separator, or common manifold. Each check valve or other means of shut-off shall be placed in the flow line serving the well so that it will permit the passage of fluids from the well and will act as a check to prevent any fluid from entering the well through the flow line from any outside source.

(b) Operator shall do all things necessary to keep the check valve or other means of shut-off in good working order, and operators, when requested by an agent of the commission, will test the check valve or other means of shut-off for leakage.

Source Note: The provisions of this §3.24 adopted to be effective January 1, 1976.

§3.25 Use of Common Storage

(a) Where oil and/or other liquid hydrocarbons are produced from two or more separate reservoirs or zones and separate proration schedules are published by the Commission for each reservoir or zone, the use of common storage is authorized as long as the requirements of §3.26 and §3.27 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil, and Gas to be Measured and Surface Commingling of Gas, respectively) are met. An operator utilizing common storage pursuant to this section shall not be required to file a separate Form P-4, Certificate of Compliance and Transportation Authority, for each reservoir or zone, but may file one form to authorize the transportation of oil or gas from all reservoirs or zones producing into common storage.

(b) A gatherer transporting oil from such common storage shall not be required to file a separate transporter's report for each separate reservoir or zone or each separate

lease but shall file such report on a combined basis for the total amount of commingled oil in common storage.

(c) The operator of a lease or leases for which the Commission has authorized the use of common storage of oil produced from two or more reservoirs or zones and from two or more leases shall file Form PR, Monthly Production Report, for each separate reservoir or zone and/or for each separate lease and, in addition thereto, said operator shall file a report showing the data included on the individual reports on a combined basis for the total amount of commingled oil in common storage.

Source Note: The provisions of this §3.25 adopted to be effective January 1, 1976; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective February 25, 2019, 44 TexReg 812.

§3.26 Separating Devices, Tanks, and Surface Commingling of Oil

(a) Where oil and gas are found in the same stratum and it is impossible to separate one from the other, or when a well has been classified as a gas well and such gas well is not connected to a cycling plant and such well is being produced on a lease and the gas is utilized under Texas Natural Resources Code §§86.181 - 86.185, the operator shall install a separating device of approved type and sufficient capacity to separate the oil and liquid hydrocarbons from the gas.

(1) A separating device shall be kept in place as long as a necessity for it exists, and its use shall not be discontinued without the consent of the Commission.

(2) All oil and any other liquid hydrocarbons as and when produced shall be adequately measured pursuant to paragraphs (3) and (4) of this subsection before the same leaves the lease from which they are produced, except for gas wells where the full well stream is moved to a plant or central separation facility in accordance with §3.55 of this title (relating to Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering) (Statewide Rule 55) and the full well stream is measured, with each completion being separately measured, before the gas leaves the lease. If an operator commingles production pursuant to subsection (b) of this section, the operator shall comply with paragraphs (3) and (4) of this subsection but the operator is not required to measure the production stream before it leaves the lease.

(3) Sufficient tankage and separator capacity shall be provided by the producer to adequately take daily gauges of all oil and any other liquid hydrocarbons unless LACT equipment, installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1 or another method approved by the Commission or its delegate, is being used to effect custody transfer.

(4) For Commission purposes, the measurement requirements of this section are satisfied by the use of coriolis or turbine meters or any other measurement device or technology that conforms to standards established, as of the time of installation, by the American Petroleum Institute (API) or the American Gas Association (AGA) for measuring oil or gas, as applicable, or approved by the Director of the Oil and Gas Division as an accurate measurement technology.

(b) Surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs is permitted and authorized if:

(1) the operator measures the production stream from each tract and each Commission-designated reservoir separately before combining it with a stream from another tract or Commission-designated reservoir; or

(2) the tracts and Commission-designated reservoirs have identical working interest and royalty interest ownership in identical percentages.

(c) Production that complies with subsection (b) of this section is authorized even if the separator, metering, or storage is located off the tract or tracts. If production is surface commingled pursuant to subsection (b) of this section, the operator shall file Form P-17A, Application for Commingle Permit Pursuant to Rules 26 and/or 27.

(d) If an operator does not meet the requirements of subsection (b) of this section, the Commission may approve surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs in order to prevent waste, to promote conservation, or to protect correlative rights.

(1) Administrative approval. After receipt of a completed Form P-17, the Commission may grant approval for surface commingling administratively when the tracts or Commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and the Commission has not received a protest to an application within 21 days of notice of the application being mailed by the applicant to all working and royalty interest owners or, if publication is required, within 21 days of the date of last publication and the applicant provides:

(A) a method of allocating production to ensure the protection of correlative rights, in accordance with subsection (e) of this section; and

(B) an affidavit or other evidence that all working interest and royalty interest owners have been notified of the application by certified mail or have provided applicant with waivers of notice requirements; or

(C) in the event the applicant is unable, after due diligence, to provide notice by certified mail to all working interest and royalty interest owners, a publisher's affidavit or other evidence that the Commission's notice of

application has been published once a week for two consecutive weeks in a newspaper of general circulation in the county or counties in which the tracts that are the subject of the application are located.

(2) Request for hearing. When the tracts or Commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and a person entitled to notice of the application has filed a protest to the application with the Commission, the applicant may request a hearing on the application. The Commission shall give notice of the hearing to all working interest and royalty interest owners. The Commission may permit the commingling if the applicant demonstrates that the proposed commingling will protect the rights of all interest owners in accordance with subsection (e) of this section and will prevent waste, promote conservation or protect correlative rights.

(e) Reasonable allocation required. The applicant must demonstrate to the Commission or its designee that the proposed commingling of hydrocarbons will not harm the correlative rights of the working or royalty interest owners of any of the wells to be commingled. The method of allocation of production to individual interests must accurately attribute to each interest its fair share of aggregated production.

(1) In the absence of contrary information, such as indications of material fluctuations in the monthly production volume of a well proposed for commingling, the Commission will presume that allocation based on the daily production rate for each well as determined and reported to the Commission by semi-annual well tests will accurately attribute to each interest its fair share of production without harm to correlative rights. As used in this section, "daily production rate" for a well means the 24 hour production rate determined by the most recent well test conducted and reported to the Commission in accordance with §§3.28, 3.52, 3.53, and 3.55 of this title (relating to Potential and Deliverability of Gas Wells to be Ascertained and Reported, Oil Well Allowable Production, Annual Well Tests and Well Status Reports Required, and Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering).

(2) Operators may test commingled wells annually after approval by the Commission or the Commission's delegate of the operator's written request demonstrating that annual testing will not harm the correlative rights of the working or royalty interest owners of the commingled wells. Allocation of commingled production shall not be based on well tests conducted less frequently than annually.

(3) Nothing in this section prohibits allocations based on more frequent well tests than the semi-annual well test set out in paragraph (1) of this subsection. Additional tests used for allocation do not have to be filed with the Commission but must be available for inspection at the request of the Commission, working interest owners or royalty interest owners.

(4) Allocations may be based on a method other than periodic well tests if the Commission or its designee determines that the alternative allocation method will insure a reasonable allocation of production as required by this paragraph.

(f) An operator that commingles production from different Commission-designated reservoirs, whether under subsection (b) or (c) of this section, shall comply with §3.10 of this title (relating to Restriction of Production of Oil and Gas from Different Strata).

(g) An operator that commingles production, whether under subsection (b) or (c) of this section, shall review and correct any forms related to its commingle permit as necessary in order to maintain accurate information on file with the Commission.

(h) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property on which it is produced.

(i) Oil gravity tests and reports (Reference Order Number 20-55, 647, effective 4-1-66, and Reference Order Number 20-58, 528, effective 5-10-68.)

(1) Where individual lease oil production, or authorized commingled oil production, separator, treating, and/or storage vessels, other than conventional emulsion breaking treaters, are connected to a gas gathering system so that heat or vacuum may be applied prior to oil measurement for Commission-required production reports, the operator may, at the operator's option, apply heat or vacuum to the oil only to the extent the average gravity of the stock tank oil will not be reduced below a limiting gravity for each lease as established by an average oil gravity test conducted under the following conditions (Reference Order Number 20-55, 647, effective 4-1-66):

(A) the separator or separator system, which shall include any type vessel that is used to separate hydrocarbons, shall be operated at not less than atmospheric pressure;

(B) no heat shall be applied;

(C) the test interval shall be for a minimum of 24 hours, and the average oil gravity after weathering for not more than 24 hours shall then become the limiting gravity factor for applying heat or vacuum to unmeasured oil on the tested lease.

(2) Initial gravity tests shall be made by the operator when such separator, treating, and/or storage vessels are first used pursuant to this section. Subsequent tests shall be made at the request of either the Commission or any interested party; and such subsequent tests shall be witnessed by the requesting party. Any interested party may witness the tests.

(3) Each operator shall enter on the required

production report the gravity of the oil delivered to market from the lease reported, and it is provided that should a volume of oil delivered to market from such lease separation facilities not meet the gravity requirement established by the described test, adjustment shall be made by charging the allowable of the lease on the relationship of the volume and the gravity of the particular crude.

(4) Where a conventional heater treater is required and is used only to break oil from an emulsion prior to oil measurement, this section will not be applicable; provided, however, that by this limitation on the section, it is not intended that excessive heat may be used in conventional heater treater, and in circumstances where such heater treater is connected to a gas gathering system and it is found by Commission investigation made on its own volition or on complaint of any interested party that excessive heat is used, either the provisions of this section or special restrictive regulation may be made applicable.

Source Note: The provisions of this §3.26 adopted January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective April 28, 2015, 40 TexReg 2275; amended to be effective February 25, 2019, 44 TexReg 812.

§3.27 Gas to be Measured and Surface Commingling of Gas

(a) All natural gas, except casinghead gas, produced from wells shall be measured, with each completion being measured separately, before the gas leaves the lease, and the producer shall report the volume produced from each completion to the Commission. For Commission purposes, the measurement requirements of this section are satisfied by the use of coriolis or turbine meters or any other measurement device or technology that conforms to standards established, as of the time of installation, by the American Petroleum Institute (API) or the American Gas Association (AGA) for measuring oil or gas, as applicable, or approved by the Director of the Oil and Gas Division as an accurate measurement technology. Exceptions to this provision may be granted by the Commission upon written application.

(b) All casinghead gas sold, processed for its gasoline content, used in a field other than that in which it is produced, or used in cycling or repressuring operations, shall be measured before the gas leaves the lease, and the producer shall report the volume produced to the Commission. Exceptions to this provision may be granted by the Commission upon written application.

(c) All casinghead gas produced in this state which is not covered by the provisions of subsection (b) of this section, shall be measured before the gas leaves the lease, is used as fuel, or is released into the air, based on its use or on periodic tests, and reported to the Commission by the producer. The volume of casinghead gas produced by wells exempt from gas/oil ratio surveys must be estimated, based on general knowledge of the characteristics of the wells. Exceptions to this provision may be granted by the Commission upon written application.

(d) Releases and production of gas at a volume or daily flow rate, commonly referred to as "too small to measure" (TSTM), which, due to minute quantity, cannot be accurately determined or for which a determination of gas volume is not reasonably practical using routine oil and gas industry methods, practices, and techniques are exempt from compliance with this rule and are not required to be reported to the Commission or charged against lease allowable production.

(e) The Commission may approve surface commingling of gas or oil and gas described in subsections (a), (b) or (c) of this section and produced from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs in accordance with §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil).

(f) In reporting gas well production, the full-well stream gas shall be reported and charged against each gas well for allowable purposes. All gas produced, including all gas used on the lease or released into the air, must be reported regardless of its disposition.

(g) If gas is produced from a lease or other property covered by the coastal or inland waters of the state, the gas produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property from which it was produced.

(h) All natural hydrocarbon gas produced and utilized from wells completed in geothermal resource reservoirs shall be measured and allocated to each individual lease based on semiannual tests conducted on full well stream lease production.

(i) For purposes of this rule, "measured" shall mean a determination of gas volume in accordance with this rule and other rules of the Commission, including accurate estimates of unmetered gas volumes released into the air or used as fuel.

(j) No meter or meter run used for measuring gas as required by this rule shall be equipped with a manifold which will allow gas flow to be diverted or bypassed around the metering element in any manner unless it is of the type listed in paragraphs (1) or (2) of this subsection:

(1) double chambered orifice meter fittings with proper meter manifolding to allow equalized pressure across the meter during servicing;

(2) double chambered or single chambered orifice meter fittings equipped with proper meter manifolding or other types of metering devices accompanied by one of the following types of meter inspection manifolds:

(A) a manifold with block valves on each end of the meter run and a single block valve in the manifold complete with provisions to seal and a continuously maintained seal record;

(B) an inspection manifold having block valves at each end of the meter run and two block valves in the manifold with a bleeder between the two and with one valve equipped with provisions to seal and continuously maintained seal records;

(C) a manifold equipped with block valves at each end of the meter run and one or more block valves in the manifold, when accompanied by a documented waiver from the owner or owners of at least 60% of the royalty interest and the owner or owners of at least 60% of the working interest of the lease from which the gas is produced.

(k) Whenever sealing procedures are used to provide security in the meter inspection manifold systems, the seal records shall be maintained for at least three years at an appropriate office and made available for Commission inspection during normal working hours. At any time a seal is broken or replaced, a notation will be made on the orifice meter chart along with graphic representation of estimated gas flow during the time the meter is out of service.

(l) All meter requirements apply to all meters which are used to measure lease production, including sales meters if sales meter volumes are allocated back to individual leases.

(m) The Commission may grant an exception to measurement requirements under subsections (a), (b) and (c) of this section if the requirements of this subsection are met. An exception granted under this subsection will be revoked if the most recent well test or production reported to the Commission reflects a production rate of more than 20 MCF of gas per day or if any of the other requirements for an exception under this subsection are no longer satisfied. An applicant seeking an exception under this subsection must file an application establishing:

(1) the most recent production test reported to the Commission demonstrates that the gas well or oil lease for which an exception is sought produces at a rate of no more than 20 MCF of gas per day;

(2) an annual test of the production of the gas well or oil lease provides an accurate estimate of the daily rate of gas flow;

(3) the flow rate established in paragraph (2) of this subsection multiplied by the recorded duration determined by any device or means that accurately records the duration of production each month yields an accurate estimate of monthly production; and

(4) the operator of the pipeline connected to the gas well or oil lease concurs in writing with the application.

(n) Failure to comply with the provisions of this rule will result in severance of the producing well, lease, facility, or gas pipeline or in other appropriate enforcement proceeding.

Source Note: The provisions of this §3.27 adopted to be effective January 1, 1976; amended to be effective April 12, 1983, 8 TexReg 1019; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective April 28, 2015, 40 TexReg 2275; amended to be effective February 25, 2019, 44 TexReg 812.

§3.28 Potential and Deliverability of Gas Wells to be Ascertained and Reported

(a) The information necessary to determine the absolute daily open flow potential of each producing associated or nonassociated gas well shall be ascertained, and a report shall be filed as required with the Commission within 90 days of completion of the well. The test shall be performed in accordance with the Commission's publication, Back Pressure Test for Natural Gas Wells, State of Texas, or other test procedure approved in advance by the Commission and shall be reported on the Commission's prescribed form. An operator may determine absolute open flow potential from a stabilized one-point test. For a one-point test, the well shall be flowed on a single choke setting until a stabilized flow is achieved, but not less than 72 hours. The shut-in and flowing bottom hole pressures shall be calculated in the manner prescribed for a four-point test. The Commission may authorize a one-point test of shorter duration for a well which is not connected to a sales line, but a test which is in compliance with this section must be conducted and reported after the well is connected before an allowable will be assigned to the well. Back-dating of allowables will be performed in accordance with §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable).

(b) After conducting the test required by subsection (a) of this section each operator of a gas well shall conduct an initial deliverability test and report the test results on the Commission's prescribed form not later than 90 days after completion of the well. If a 72-hour one-point back pressure test on a well connected to a sales line was conducted as provided in subsection (a) of this section, the same test may be used to determine initial deliverability, provided the test was conducted in accordance with subsection (c) of this section.

(1) After the initial deliverability test has been conducted, the following schedule for well testing applies:

(A) Nonassociated gas wells shall be tested semiannually.

(B) Associated gas wells described in §3.49(b) of this title (relating to Gas-Oil Ratio) shall be tested annually.

(C) Wells with current reported deliverability of 100 Mcf a day or less are not required to test as long as

deliverability and production remain at or below 100 Mcf a day but are required to file Form G-10 according to the instructions on the form.

(D) Wells with a deliverability greater than 100 Mcf a day and less than or equal to 250 Mcf a day in fields without special field rules are not required to be tested as long as deliverability and production remain equal to or less than 250 Mcf a day.

(2) Notwithstanding any of the provisions in this section on frequency of testing, gas wells commingling liquid hydrocarbons before metering must comply with the testing provisions applicable to such wells.

(3) All deliverability tests shall be conducted in accordance with subsection (c) of this section and the instructions printed on the Form G-10. The results of each test shall be attested to by the operator or its appointed agent. The first purchaser or its representative upon request to the operator shall have the right to witness such tests. Gas meter charts, printouts, or other documents showing the actual measurement of the gas produced or other data required to be recorded during any deliverability test conducted under this subsection shall be preserved as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements).

(4) In the event that the first purchaser and the operator cannot agree upon the validity of the test results, then either party may request a retest of the well. The first purchaser upon request to the operator shall have the right to witness the retest. If either party requests a representative from the Commission to witness a retest of the well, the results of a Commission-witnessed test shall be conclusive for the purposes of this section until the next regularly scheduled test of the well. In the event a retest is witnessed by the Commission, the retest shall be signed by the representative of the Commission.

(5) In the event that downhole remedial work or other substantial production enhancement work is performed, or if a pumping unit, compressor, or other equipment is installed to increase deliverability of a well subject to the Commission-witnessed testing procedure described in this subsection, a new test may be requested and shall be performed according to the procedure outlined in this subsection.

(c) Unless applicable special field rules provide otherwise or the director of the oil and gas division or the director's delegate authorizes an alternate procedure due to a well's producing characteristics, deliverability tests shall be performed as follows. Deliverability tests shall be scheduled by the producer within the testing period designated by the Commission, and only the recorded data specified by the Form G-10 is required to be reported. All deliverability tests shall be performed by producing the subject well at stabilized rates for a minimum time period of 72 hours. A deliverability test shall be conducted under normal and usual operating conditions using the normal and usual operating equipment in place on the well being tested, and the well shall be produced against the normal and usual line pressure prevailing in the line into which the well produces. The average daily producing rate for each 24-hour period, the wellhead pressure before the commencement of the 72-hour test, and the flowing wellhead pressure at the beginning of each 24-hour period shall be recorded. In addition, a 24-hour shut-in wellhead pressure shall be determined either within the six-month period prior to the commencement of the 72-hour deliverability test or immediately after the completion of the deliverability test. The shut-in wellhead pressure that was determined and the date on which the 24-hour test was commenced shall be recorded on Form G-10. Exceptions and extensions to the timing requirements for deliverability tests and shut-in wellhead pressure tests may be granted by the Commission for good cause. The flow rate during each day of the first 48 hours of the test must be as close as possible to the flow rate during the final 24 hours of the test, but must equal at least 75% of such flow rate. The deliverability of the well during the last 24 hours of the flow test shall be used for allowable and allocation purposes. If pipeline conditions exist such that a producer believes a representative deliverability test cannot be performed, the producer with pipeline notification may request in writing that the Commission use either of the following as the deliverability of record:

(1) the deliverability test performed during the previous testing period; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(d) After the initial deliverability test, an operator may elect not to perform and/or file a subsequent deliverability test for a well. In those cases, the Commission shall use the lesser of the following as the deliverability of record for the purpose of this section:

(1) the results of the most recent deliverability test on file with the Commission; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(e) Notwithstanding subsection (d) of this section, a deliverability test must be performed on a well in accordance with this section:

(1) at initial completion of the well;

(2) at recompletion of the well into a different regulatory field;

(3) at reclassification of the well from oil to gas;

(4) when the well is an inactive well as defined in §3.15 of this title (relating to Surface Equipment Removal Requirements and Inactive Wells) and the operator resumes production from the well;

(5) when the well is completed in a regulatory field where the allocation formula is based in whole or in part on the downhole pressure of the well, and that allocation formula is not suspended;

(6) when necessary to reinstate an allowable; or

(7) when required by Commission order, special field rule, or other Commission rule.

(f) If the deliverability of a well changes after a test is reported to the Commission, the deliverability of record for a well will be decreased upon receipt of a written request from the operator to reduce the deliverability of record to a specified amount. If the deliverability of a well increases, a retest must be conducted in the manner specified in this section and must be reported on Form G-10 before the deliverability of record will be increased.

(g) First purchasers with packages of gas dedicated entirely to a downstream purchaser shall coordinate testing with and provide test results to that downstream purchaser if requested by the downstream purchaser. In these cases, the downstream purchaser upon request to the operator shall have the right to witness all deliverability tests and retests.

(h) Tests of wells connected to a pipeline shall be made in a manner that no gas is flared, vented, or otherwise wastefully used.

Source Note: The provisions of this §3.28 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective October 12, 1998, 23 TexReg 10397; amended to be effective February 28, 2000, 25 TexReg 1592; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 1, 2017, 41 TexReg 9470.

§3.29 Hydraulic Fracturing Chemical Disclosure Requirements

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

(1) Accredited laboratory--A laboratory as defined in Texas Water Code, §5.801.

(2) Additive--Any chemical substance or combination of substances, including a proppant, contained in a hydraulic fracturing fluid that is intentionally added to a base fluid for a specific purpose whether or not the purpose of any such substance or combination of substances is to create fractures in a formation.

(3) Adjacent property--A tract of property next to the tract of property on which the subject wellhead is located, including a tract that meets only at a corner point.

(4) API number--A unique, permanent, numeric identifier assigned to each well drilled for oil or gas in the United States.

(5) Base fluid--The continuous phase fluid type, such as water, used in a particular hydraulic fracturing treatment.

(6) Chemical Abstracts Service--The division of the American Chemical Society that is the globally recognized authority for information on chemical substances.

(7) Chemical Abstracts Service number or CAS number--The unique identification number assigned to a chemical by the Chemical Abstracts Service.

(8) Chemical Disclosure Registry--The chemical registry website known as FracFocus developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

(9) Chemical family--A group of chemical ingredients that share similar chemical properties and have a common general name.

(10) Chemical ingredient--A discrete chemical constituent with its own specific name or identity, such as a CAS number, that is contained in an additive.

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

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

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

(14) Health professional or emergency responder--A physician, physician's assistant, industrial hygienist, toxicologist, epidemiologist, nurse, nurse practitioner, or emergency responder who needs information in order to provide medical or other health services to a person exposed to a chemical ingredient.

(15) Hydraulic fracturing fluid--The fluid, including the applicable base fluid and all additives, used to perform a particular hydraulic fracturing treatment.

(16) Hydraulic fracturing treatment--The treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas.

(17) Landowner--The person listed on the applicable county appraisal roll as owning the real property on which the relevant wellhead is located.

(18) Operator--An operator as defined in Texas Natural Resources Code, Chapter 89.

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

(20) Proppant--Sand or any natural or man-made material that is used in a hydraulic fracturing treatment to prop open the artificially created or enhanced fractures once the treatment is completed.

(21) Requestor--A person who is eligible to request information claimed to be entitled to trade secret protection in accordance with Texas Natural Resources Code, §91.851(a)(5).

(22) Service company--A person that performs hydraulic fracturing treatments on a well in this state.

(23) Supplier--A company that sells or provides an additive for use in a hydraulic fracturing treatment.

(24) Total water volume--The total amount of water in gallons used as the carrier fluid for the hydraulic fracturing job. It may include recycled water and newly acquired water.

(25) Trade name--The name given to an additive or a hydraulic fracturing fluid system under which that additive or hydraulic fracturing fluid system is sold or marketed.

(26) Trade secret--Any formula, pattern, device, or compilation of information that is used in a person's business, and that gives the person an opportunity to obtain an advantage over competitors who do not know or use it. The six factors considered in determining whether information qualifies as a trade secret, in accordance with the definition of "trade secret" in the Restatement of Torts, Comment B to Section 757 (1939), as adopted by the Texas Supreme Court in *Hyde Corp. v. Huffines,* 314 S.W.2d 763, 776 (Tex. 1958), include:

(A) the extent to which the information is known outside of the company;

(B) the extent to which it is known by employees and others involved in the company's business;

(C) the extent of measures taken by the company to guard the secrecy of the information;

(D) the value of the information to the company and its competitors;

(E) the amount of effort or money expended by the company in developing the information; and

(F) the ease or difficulty with which the information could be properly acquired or duplicated by others.

(27) Well--A well as defined in Texas Natural Resources Code, Chapter 89.

(28) Well completion report--The report an operator is required to file with the Commission following the completion or recompletion of a well, if applicable, in accordance with §3.16(b) of this title (relating to Log and Completion or Plugging Report.)

(b) Applicability. This section applies to a hydraulic fracturing treatment performed on a well in the State of Texas for which the Commission has issued an initial drilling permit on or after February 1, 2012.

(c) Required disclosures.

(1) Supplier and service company disclosures.

(A) As soon as possible, but not later than 15 days following the completion of hydraulic fracturing treatment(s) on a well, the supplier or the service company must provide to the operator of the well the following information concerning each chemical ingredient intentionally added to the hydraulic fracturing fluid:

(i) each additive used in the hydraulic fracturing fluid and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment;

(ii) each chemical ingredient subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2);

(iii) all other chemical ingredients not submitted under subparagraph (A) of this paragraph that were intentionally included in, and used for the purpose of creating, hydraulic fracturing treatment(s) for the well;

(iv) the actual or maximum concentration of each chemical ingredient listed under clause (i) or clause (ii) of this subparagraph in percent by mass; and

(v) the CAS number for each chemical ingredient, if applicable.

(B) The supplier or service company must provide the operator of the well a written statement that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) of the operator's well is claimed to be entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552. If the chemical ingredient name and/or CAS number is claimed as trade secret information, the supplier or service company making the claim must provide:

(i) the supplier's or service company's contact information, including the name, authorized representative, mailing address, and telephone number; and

(ii) the chemical family, unless providing the chemical family would disclose information protected as a trade secret.

(2) Operator disclosures.

(A) On or before the date the well completion report for a well on which hydraulic fracturing treatment(s) was/were conducted is submitted to the Commission in accordance with §3.16(b) of this title, the operator of the well must complete the Chemical Disclosure Registry form and upload the form on the Chemical Disclosure Registry, including:

(i) the operator name;

(ii) the date of completion of the hydraulic fracturing treatment(s);

(iii) the county in which the well is located;

(iv) the API number for the well;

(v) the well name and number;

(vi) the longitude and latitude of the wellhead;

(vii) the total vertical depth of the well;

(viii) the total volume of water used in the hydraulic fracturing treatment(s) of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment(s), if something other than water;

(ix) each additive used in the hydraulic fracturing treatments and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment(s);

(x) each chemical ingredient used in the hydraulic fracturing treatment(s) of the well that is subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), as provided by the chemical supplier or service company or by the operator, if the operator provides its own chemical ingredients;

(xi) the actual or maximum concentration of each chemical ingredient listed under clause (x) of this subparagraph in percent by mass;

(xii) the CAS number for each chemical ingredient listed, if applicable; and

(xiii) a supplemental list of all chemicals and their respective CAS numbers, not subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), that were intentionally included in and used for the purpose of creating the hydraulic fracturing treatments for the well.

(B) If the Chemical Disclosure Registry known as FracFocus is temporarily inoperable, the operator of a well on which hydraulic fracturing treatment(s) were performed must supply the Commission with the required information with the well completion report and must upload the information on the FracFocus Internet website when the website is again operable. If the Chemical Registry known as FracFocus is discontinued or becomes permanently inoperable, the information required by this rule must be filed as an attachment to the completion report for the well, which is posted, along with all attachments, on the Commission's Internet website, until the Commission amends this rule to specify another publicly accessible Internet website.

(C) If the supplier, service company, or operator claim that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) is entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552, the operator of the well must indicate on the Chemical Disclosure Registry form or the supplemental list that the additive or chemical ingredient is claimed to be entitled to trade secret protection. If a chemical ingredient name and/or CAS number is claimed to be entitled to trade secret protection, the chemical family or other similar description associated with such chemical ingredient must be provided. The operator of the well on which the hydraulic fracturing treatment(s) were performed must provide the contact information, including the name, authorized representative, mailing address, and phone number of the business organization claiming entitlement to trade secret protection.

(D) Unless the information is entitled to protection as a trade secret under Texas Government Code, Chapter 552, information submitted to the Commission or uploaded on the Chemical Disclosure Registry is public information.

(3) Inaccuracies in information. A supplier is not responsible for any inaccuracy in information that is provided to the supplier by a third party manufacturer of the additives. A service company is not responsible for any inaccuracy in information that is provided to the service company by the supplier. An operator is not responsible for any inaccuracy in information provided to the operator by the supplier or service company.

(4) Disclosure to health professionals and emergency responders. A supplier, service company or operator may not withhold information related to chemical ingredients used in a hydraulic fracturing treatment, including information identified as a trade secret, from any health professional or emergency responder who needs the information for diagnostic, treatment or other emergency response purposes subject to procedures set forth in 29 Code of Federal Regulations §1910.1200(i). A supplier, service company or operator must provide directly to a health professional or emergency responder, all information in the person's possession that is required by the health professional or emergency responder, whether or not the information may qualify for trade secret protection under subsection (e) of this section. The person disclosing information to a health professional or emergency responder must include with the disclosure, as soon as circumstances permit, a statement of the health professional's confidentiality obligation. In an emergency situation, the supplier, service company or operator must provide the information immediately upon request to the

person who determines that the information is necessary for emergency response or treatment. The disclosures required by this subsection must be made in accordance with the procedures in 29 Code of Federal Regulations §1910.1200(i) with respect to a written statement of need and confidentiality agreements, as applicable.

(d) Disclosures not required. A supplier, service company, or operator is not required to:

(1) disclose ingredients that are not disclosed to it by the manufacturer, supplier, or service company;

(2) disclose ingredients that were not intentionally added to the hydraulic fracturing treatment;

(3) disclose ingredients that occur incidentally or are otherwise unintentionally present which may be present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid; or

(4) identify specific chemical ingredients and/or their CAS numbers that are claimed as entitled to trade secret protection based on the additive in which they are found or provide the concentration of such ingredients, unless the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission.

(e) Trade secret protection.

(1) A supplier, service company, or operator is not required to disclose trade secret information, unless the Office of the Attorney General or a court of proper jurisdiction determines that the information is not entitled to trade secret protection under Texas Government Code, Chapter 552.

(2) If the specific identity and/or CAS number of a chemical ingredient, the concentration of a chemical ingredient, or both the specific identity and/or CAS number and concentration of a chemical ingredient are claimed or have been finally determined to be entitled to protection as a trade secret under Texas Government Code, Chapter 552, the supplier, service company, or operator, as applicable, may withhold the specific identity and/or CAS number, the concentration, or both the specific identity and/or CAS number and concentration, of the chemical ingredient from the information provided to the operator. If the supplier, service company, or operator, as applicable, elects to withhold that information, the supplier, service company, or operator, as applicable, must provide to the operator or the Commission, as applicable, information that:

(A) indicates that the specific identity and/or CAS number of the chemical ingredient, the concentration of the chemical ingredient, or both the specific identity and/or CAS number and concentration of the chemical ingredient are entitled to protection as trade secret information; and

(B) discloses the chemical family associated with the chemical ingredient; or

(C) discloses the properties and effects of the chemical ingredient(s), the identity of which is withheld.

(f) Trade secret challenge.

(1) The following persons may submit a request challenging a claim of entitlement to trade secret protection for any chemical ingredients and/or CAS numbers used in the hydraulic fracturing treatment(s) of a well:

(A) the landowner on whose property the relevant wellhead is located;

(B) the landowner who owns real property adjacent to property described in subparagraph (A) of this paragraph; or

(C) a department or agency of this state with jurisdiction over a matter to which the claimed trade secret information is relevant.

(2) A requestor must certify in writing to the director, over the requestor's signature, to the following:

(A) the requestor's name, address, and daytime phone number;

(B) if the requestor is a landowner, a statement that the requestor is listed on the county appraisal roll as owning the property on which the relevant wellhead is located or is listed on the county appraisal roll as owning property adjacent to the property on which the relevant wellhead is located;

(C) the county in which the wellhead is located; and

(D) the API number or other Railroad Commission of Texas identifying information, such as field name, oil lease name and number, gas identification number, and well number.

(3) A requestor may use the following format to provide the written certification required by paragraph (2) of this subsection:

REQUEST TO CHALLENGE CLAIM OF ENTITLEMENT
TO TRADE SECRET PROTECTION OF HYDRAULIC FRACTURING
TREATMENT CHEMICAL COMPOSITION

I, _____(name)_____, challenge the claim of entitlement to trade secret protection for portions of the chemicals or other substances used in the hydraulic fracturing treatment of the following well:

Operator name: _____
County name: _____
API number: _____
Field Name: _____
Railroad Commission oil lease name and number: _____
Railroad Commission gas identification number: _____
Well Number: _____

The following is to be completed if the requestor is a landowner:

I certify that I am listed on the appraisal roll as owning the property on which the relevant wellhead is located or I am listed on the appraisal roll as owning property adjacent to the property on which the relevant wellhead is located.

Name of requestor: _____
Mailing address of Requestor:

_____

_____

Phone number of requestor: _____
Email address of requestor (optional):

_____

EMAIL ADDRESS: YOU ARE NOT REQUIRED TO PROVIDE AN EMAIL ADDRESS when completing and filing this form. Please be aware that information provided to any governmental body may be subject to disclosure pursuant to the Texas Public Information Act or other applicable federal or state legislation. IF YOU PROVIDE AN EMAIL ADDRESS, YOU AFFIRMATIVELY CONSENT TO THE RELEASE OF THAT EMAIL ADDRESS TO THIRD PARTIES. Other departments within the Railroad Commission also may use the email address you provide to communicate with you.

Signature of Requestor: _____

Date: _____

(4) A requestor must file a request no later than 24 months from the date the operator filed the well completion report for the well on which the hydraulic fracturing treatment(s) were performed. A landowner who owned the property on which the wellhead is located, or owned adjacent property, on or after the date the operator filed with the Commission the completion report for the subject well may challenge a claim of entitlement to trade secret protection within that 24-month period only. The Commission will determine whether or not the request has been received within the allowed 24-month period.

(5) If the Commission determines that the request has been received within the allowed 24-month period and the certification is properly completed and signed, the Commission will consider this sufficient for the purpose of forwarding the request to the Office of the Attorney General.

(6) Within 10 business days of receiving a request that complies with paragraph (2) of this subsection, the director must:

(A) submit to Office of the Attorney General, Open Records Division, a request for decision regarding the challenge;

(B) notify the operator of the subject well and the owner of the claimed trade secret information of the submission of the request to the Office of the Attorney General and of the requirement that the owner of the claimed trade secret information submit directly to the Office of Attorney General, Open Records Division, the claimed trade secret information, clearly marked "confidential," submitted under seal; and

(C) inform the owner of the claimed trade secret information of the opportunity to substantiate to the Office of the Attorney General, Open Records Division, its claim of entitlement of trade secret protection, in accordance with Texas Government Code, Chapter 552.

(7) If the Office of the Attorney General determines that the claim of entitlement to trade secret protection is valid under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information shall not be required to disclose the trade secret information, subject to appeal.

(8) The request shall be deemed withdrawn if, prior to the determination of the Office of the Attorney General on the validity of the trade secret claim, the owner of the claimed trade secret information provides confirmation to the Commission and the Office of the Attorney General that the owner of the claimed trade secret information has voluntarily provided the information that is the subject of the request to the requestor subject to a claim of trade secret protection, or the requestor submits to the Commission and the Office of the Attorney General a written notice withdrawing the request.

(9) A final determination by the Office of the Attorney General regarding the challenge to the claim of entitlement of trade secret protection of any withheld information may be appealed within 10 business days to a district court of Travis County pursuant to Texas Government Code, Chapter 552.

(10) If the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the withheld information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information must disclose such information to the requestor as directed by the Office of the Attorney General or a court of proper jurisdiction on appeal.

(g) Trade secret confidentiality. A health professional or emergency responder to whom information is disclosed under subsection (c)(4) of this section must hold the information confidential, except that the health professional or emergency responder may, for diagnostic or treatment purposes, disclose information provided under that subsection to another health professional, emergency responder, or accredited laboratory. A health professional, emergency responder, or accredited laboratory to which information is disclosed by another health professional or emergency responder under this subsection must hold the information confidential and the disclosing health professional or emergency responder must include with the disclosure, or in a medical emergency, as soon as circumstances permit, a statement of the recipient's confidentiality obligation pursuant to this subsection.

(h) Penalties. A violation of this section may subject a person to any penalty or remedy specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the Commission. 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) (Rule 73) for violation of this section.

Source Note: The provisions of this §3.29 adopted to be effective January 2, 2012, 36 TexReg 9307.

§3.30 Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)

(a) Need for agreement. Several statutes cover persons and activities where the respective jurisdictions of the RRC and the TCEQ may intersect. This rule is a statement of how the agencies implement the division of jurisdiction.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the

Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) Texas Health and Safety Code, §401.414, relating to Memoranda of Understanding, requires the Railroad Commission of Texas and the Texas Commission on Environmental Quality to adopt a memorandum of understanding (MOU) defining the agencies' respective duties under Texas Health and Safety Code, Chapter 401, relating to radioactive materials and other sources of radiation. Texas Health and Safety Code, §401.415, relating to oil and gas naturally occurring radioactive material (NORM) waste, provides that the Railroad Commission of Texas shall issue rules on the management of oil and gas NORM waste, and in so doing shall consult with the Texas Natural Resource Conservation Commission (now TCEQ) and the Department of Health (now Department of State Health Services) regarding protection of the public health and the environment.

(3) Texas Water Code, Chapters 26 and 27, provide that the Railroad Commission and TCEQ collaborate on matters related to discharges, surface water quality, groundwater protection, underground injection control and geologic storage of carbon dioxide. Texas Water Code, §27.049, relating to Memorandum of Understanding, requires the RRC and TCEQ to adopt a new MOU or amend the existing MOU to reflect the agencies' respective duties under Texas Water Code, Chapter 27, Subchapter C-1 (relating to Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide).

(4) The original MOU between the agencies adopted pursuant to House Bill 1407 (67th Legislature, 1981) became effective January 1, 1982. The MOU was revised effective December 1, 1987, May 31, 1998, August 30, 2010, and again on May 1, 2012, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Natural Resource Conservation Commission's (the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health) jurisdiction over industrial and hazardous wastes.

(5) The agencies have determined that the revised MOU that became effective on May 1, 2012, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission).

(A) Solid waste. Under Texas Health and Safety Code, Chapter 361, §§361.001 - 361.754, the TCEQ has jurisdiction over solid waste. The TCEQ's jurisdiction encompasses hazardous and nonhazardous, industrial and municipal, solid wastes.

(i) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(ii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste excludes "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code. . . ."

(iii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste includes the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA. . . ."

(iv) After delegation of RCRA authority to the RRC, the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(B) Water quality.

(i) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges into or adjacent to water in the state, except for discharges regulated by the RRC. Upon delegation from the United States Environmental Protection Agency to the TCEQ of authority to issue permits for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. For the purposes of TCEQ's implementation of Texas Water Code, §26.131, "produced water" is defined as all wastewater associated with oil and gas exploration, development, and production activities, except hydrostatic test water and gas plant effluent, that is discharged into water in the state, including waste streams regulated by 40 CFR Part 435.

(ii) Discharge permits existing on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. RRC permits issued prior to TCEQ delegation of NPDES authority shall remain effective until revoked or expired. Amendment or renewal of such permits on or after the effective date of delegation shall be pursuant to TCEQ's TPDES authority. The TPDES permit will supersede and replace the RRC permit. For facilities that have both an RRC permit and an EPA permit, TCEQ will issue the TPDES permit upon amendment or renewal of the RRC or EPA permit, whichever occurs first.

(iii) Discharge applications pending on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. TCEQ shall assume authority for discharge applications pending at the time TCEQ receives delegation from EPA. The RRC will provide TCEQ the permit application and any other relevant information necessary to administratively and technically review and process the applications. TCEQ will review and process these pending applications in accordance with TPDES requirements.

(iv) Storm water. TCEQ has jurisdiction over storm water discharges that are required to be permitted pursuant to Title 40 Code of Federal Regulations (CFR) Part 122.26, except for discharges regulated by the RRC. Discharge of storm water regulated by TCEQ may be authorized by an individual Texas Pollutant Discharge Elimination System (TPDES) permit or by a general TPDES permit. These storm water permits may also include authorizations for certain minor types of non-storm water discharges.

(I) Storm water associated with industrial activities. The TCEQ regulates storm water discharges associated with certain industrial activities under individual TPDES permits and under the TPDES Multi-Sector General Permit, except for discharges associated with industrial activities under the jurisdiction of the RRC.

(II) Storm water associated with construction activities. The TCEQ regulates storm water discharges associated with construction activities, except for discharges from construction activities under the jurisdiction of the RRC.

(III) Municipal storm water discharges. The TCEQ has jurisdiction over discharges from regulated municipal storm sewer systems (MS4s).

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the TCEQ, and a portion of a site is regulated by the EPA and RRC, storm water authorization must be obtained from the TCEQ for the portion(s) of the site regulated by the TCEQ, and from the EPA and the RRC, as applicable, for the RRC regulated portion(s) of the site. Discharge of storm water from a facility that stores both refined products intended for off-site use and crude oil in aboveground tanks is regulated by the TCEQ.

(v) State water quality certification. Under the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341), the TCEQ performs state water quality certifications for activities that require a federal license or permit and that may result in a discharge to waters of the United States, except for those activities regulated by the RRC.

(vi) Commercial brine extraction and evaporation. Under Texas Water Code, §26.132, the TCEQ has jurisdiction over evaporation pits operated for the commercial production of brine water, minerals, salts, or other substances that naturally occur in groundwater and that are not regulated by the RRC.

(C) Injection wells. Under the Texas Water Code, Chapter 27, the TCEQ has jurisdiction to regulate and authorize the drilling, construction, operation, and closure of injection wells unless the activity is subject to the jurisdiction of the RRC. Injection wells under TCEQ's jurisdiction are identified in 30 TAC §331.11 (relating to Classification of Injection Wells) and include:

(i) Class I injection wells for the disposal of hazardous, radioactive, industrial or municipal waste that inject fluids below the lower-most formation which within 1/4 mile of the wellbore contains an underground source of drinking water;

(ii) Class III injection wells for the extraction of minerals including solution mining of sodium sulfate, sulfur, potash, phosphate, copper, uranium and the mining of sulfur by the Frasch process;

(iii) Class IV injection wells for the disposal of hazardous or radioactive waste which inject fluids into or above formations that contain an underground source of drinking water; and

(iv) Class V injection wells that are not under the jurisdiction of the RRC, such as aquifer remediation wells, aquifer recharge wells, aquifer storage wells, large capacity septic systems, storm water drainage wells, salt water intrusion barrier wells, and closed loop geothermal

wells.

(2) Railroad Commission of Texas (RRC).

(A) Oil and gas waste.

(i) Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including storage, handling, reclamation, gathering, transportation, or distribution of crude oil or natural gas by pipeline, prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel, are under the jurisdiction of the RRC, except as noted in clause (ii) of this subparagraph. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (relating to exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found at §3.8(a)(30) of this title (relating to Water Protection) and at 30 TAC §335.1 (relating to Definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of oil and gas naturally occurring radioactive material (NORM) waste that constitutes, is contained in, or has contaminated oil and gas waste.

(ii) Hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(B) Water quality.

(i) Discharges. Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, the RRC regulates discharges from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities, except that on delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. Discharges regulated by the RRC into or adjacent to water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violation of such standards resulting from activities regulated by the RRC. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. The TCEQ and the RRC may consult as necessary regarding application and interpretation of Texas Surface Water Quality Standards.

(ii) Storm water. When required by federal law, authorization for storm water discharges that are under the jurisdiction of the RRC must be obtained through application for a National Pollutant Discharge Elimination System (NPDES) permit with the EPA and authorization from the RRC, as applicable.

(I) Storm water associated with industrial activities. Where required by federal law, discharges of storm water associated with facilities and activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain Best Management Practices (BMPs) to minimize discharges of pollutants, including sediment, in storm water to help ensure protection of surface water quality during storm events.

(II) Storm water associated with construction activities. Where required by federal law, discharges of storm water associated with construction activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Activities under RRC jurisdiction include construction of a facility that, when completed, would be associated with the exploration, development, or production of oil or gas or geothermal resources, such as a well site; treatment or storage facility; underground hydrocarbon or natural gas storage facility; reclamation plant; gas processing facility; compressor station; terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility; a carbon dioxide geologic storage facility under the jurisdiction of the RRC; and a gathering, transmission, or distribution pipeline that will transport crude oil or natural gas, including natural gas liquids, prior to refining of such oil or the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The RRC also has jurisdiction over storm water from land disturbance associated with a site survey that is conducted prior to construction of a facility that would be regulated by the RRC. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the

facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain BMPs to minimize discharges of pollutants, including sediment, in storm water during construction activities to help ensure protection of surface water quality during storm events.

(III) Municipal storm water discharges. Storm water discharges from facilities regulated by the RRC located within an MS4 are not regulated by the TCEQ. However, a municipality may regulate storm water discharges from RRC sites into their MS4.

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the RRC and the EPA, and a portion of a site is regulated by the TCEQ, storm water authorization must be obtained from the EPA and the RRC, as applicable, for the portion(s) of the site under RRC jurisdiction and from the TCEQ for the TCEQ regulated portion(s) of the site. Discharge of storm water from a terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility is under the jurisdiction of the RRC.

(iii) State water quality certification. The RRC performs state water quality certifications, as authorized by the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341) for activities that require a federal license or permit and that may result in any discharge to waters of the United States for those activities regulated by the RRC.

(C) Injection wells. The RRC has jurisdiction over the drilling, construction, operation, and closure of the following injection wells.

(i) Disposal wells. The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101.

(ii) Enhanced recovery wells. The RRC has jurisdiction over wells into which fluids are injected for enhanced recovery of oil or natural gas.

(iii) Brine mining. Under Texas Water Code, §27.036, the RRC has jurisdiction over brine mining and may issue permits for injection wells.

(iv) Geologic storage of carbon dioxide. Under Texas Water Code, §27.011 and §27.041, and subject to the review of the legislature based on the recommendations made in the preliminary report described by Section 10, Senate Bill No. 1387, Acts of the 81st Legislature, Regular Session (2009), the RRC has jurisdiction over geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir and over a well used for such injection purposes regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and converted.

(v) Hydrocarbon storage. The RRC has jurisdiction over wells into which fluids are injected for storage of hydrocarbons that are liquid at standard temperature and pressure.

(vi) Geothermal energy. Under Texas Natural Resources Code, Chapter 141, the RRC has jurisdiction over injection wells for the exploration, development, and production of geothermal energy and associated resources.

(vii) In situ tar sands. Under Texas Water Code, §27.035, the RRC has jurisdiction over the in situ recovery of tar sands and may issue permits for injection wells used for the in situ recovery of tar sands.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §§6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that

are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over waste from specific activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC. Wastes from oil, gas, and geothermal exploration activities subject to regulation by the RRC when those wastes are to be processed, treated, or disposed of at a solid waste management facility authorized by the TCEQ under 30 TAC Chapter 330 are, as defined in 30 TAC §330.3(148) (relating to Definitions), "special wastes."

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste that results from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic sewage, and trash are subject to the jurisdiction of the RRC.

(3) Storage of oil.

(A) Tank bottoms and other wastes from the storage of crude oil (whether foreign or domestic) before it enters the refinery are under the jurisdiction of the RRC. In addition, waste resulting from storage of crude oil at refineries is subject to the jurisdiction of the TCEQ.

(B) Wastes generated from storage tanks that are part of the refinery and wastes resulting from the wholesale and retail marketing of refined products are subject to the jurisdiction of the TCEQ.

(4) Underground hydrocarbon storage. The disposal of wastes, including saltwater, resulting from the construction, creation, operation, maintenance, closure, or abandonment of an "underground hydrocarbon storage facility" is subject to the jurisdiction of the RRC, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" have the meanings set out in Texas Natural Resources Code, §91.201.

(5) Underground natural gas storage. The disposal of wastes resulting from the construction, operation, or abandonment of an "underground natural gas storage facility" is subject to the jurisdiction of the RRC, provided that the terms "natural gas" and "storage facility" have the meanings set out in Texas Natural Resources Code, §91.173.

(6) Transportation of crude oil or natural gas.

(A) Jurisdiction over pipeline-related activities. The RRC has jurisdiction over matters related to pipeline safety for pipelines in Texas, as referenced in §8.1 of this title (relating to General Applicability and Standards) pursuant to Chapter 121 of the Texas Utilities Code and Chapter 117 of the Texas Natural Resources Code. The RRC has jurisdiction over spill response and remediation of releases from pipelines transporting crude oil, natural gas, and condensate that originate from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC is responsible for water quality certification issues related to construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines transporting carbon dioxide.

(B) Crude oil and natural gas are transported by railcars, tank trucks, barges, tankers, and pipelines. The RRC has jurisdiction over waste from the transportation of crude oil by pipeline, regardless of the crude oil source (foreign or domestic) prior to arrival at a refinery. The RRC also has jurisdiction over waste from the transportation by pipeline of natural gas, including natural gas liquids, prior to the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The transportation wastes subject to the jurisdiction of the RRC include wastes from pipeline compressor or pressure stations and wastes from pipeline hydrostatic pressure tests and other pipeline operations. These wastes include waste hydrocarbons (including used oil), treating and cleaning chemicals, filters (including used oil filters), scraper trap sludge, trash, domestic sewage, wastes contaminated with

polychlorinated biphenyls (PCBs) (including transformers, capacitors, ballasts, and soils), soils contaminated with mercury from leaking mercury meters, asbestos insulation, transite pipe, and hydrostatic test waters.

(C) The TCEQ has jurisdiction over waste from transportation of refined products by pipeline.

(D) The TCEQ also has jurisdiction over wastes associated with transportation of crude oil and natural gas, including natural gas liquids, by railcar, tank truck, barge, or tanker.

(7) Reclamation plants.

(A) The RRC has jurisdiction over wastes from reclamation plants that process wastes from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, such as lease tank bottoms. Waste management activities of reclamation plants for other wastes are subject to the jurisdiction of the TCEQ.

(B) The RRC has jurisdiction over the conservation and prevention of waste of crude oil and therefore must approve all movements of crude oil-containing materials to reclamation plants. The applicable statute and regulations consist primarily of reporting requirements for accounting purposes.

(8) Refining of oil.

(A) The management of wastes resulting from oil refining operations, including spent caustics, spent catalysts, still bottoms or tars, and American Petroleum Institute (API) separator sludges, is subject to the jurisdiction of the TCEQ. The processing of light ends from the distillation and cracking of crude oil or crude oil products is considered to be a refining operation. The term "refining" does not include the processing of natural gas or natural gas liquids.

(B) The RRC has jurisdiction over refining activities for the conservation and the prevention of waste of crude oil. The RRC requires that all crude oil streams into or out of a refinery be reported for accounting purposes. In addition, the RRC requires that materials recycled and used as a fuel, such as still bottoms or waste crude oil, be reported.

(9) Natural gas or natural gas liquids processing plants (including gas fractionation facilities) and pressure maintenance or repressurizing plants. Wastes resulting from activities associated with these facilities include produced water, cooling tower water, sulfur bead, sulfides, spent caustics, sweetening agents, spent catalyst, waste hydrocarbons (including used oil), asbestos insulation, wastes contaminated with PCBs (including transformers, capacitors, ballasts, and soils), treating and cleaning chemicals, filters, trash, domestic sewage, and dehydration materials. These wastes are subject to the jurisdiction of the RRC under Texas Natural Resources Code, §1.101. Disposal of waste from activities associated with natural gas or natural gas liquids processing plants (including gas fractionation facilities), and pressure maintenance or repressurizing plants by injection is subject to the jurisdiction of the RRC under Texas Water Code, Chapter 27. However, until delegation of authority under RCRA to the RRC, the TCEQ shall have jurisdiction over wastes resulting from these activities that are not exempt from federal hazardous waste regulation under RCRA and that are considered hazardous under applicable federal rules.

(10) Manufacturing processes.

(A) Wastes that result from the use of natural gas, natural gas liquids, or products refined from crude oil in any manufacturing process, such as the production of petrochemicals or plastics, or from the manufacture of carbon black, are industrial wastes subject to the jurisdiction of the TCEQ. The term "manufacturing process" does not include the processing (including fractionation) of natural gas or natural gas liquids at natural gas or natural gas liquids processing plants.

(B) The RRC has jurisdiction under Texas Natural Resources Code, Chapter 87, to regulate the use of natural gas in the production of carbon black.

(C) Biofuels. The TCEQ has jurisdiction over wastes associated with the manufacturing of biofuels and biodiesel. TCEQ Regulatory Guidance Document RG-462 contains additional information regarding biodiesel manufacturing in the state of Texas.

(11) Commercial service company facilities and training facilities.

(A) The TCEQ has jurisdiction over wastes generated at facilities, other than actual exploration, development, or production sites (field sites), where oil and gas industry workers are trained. In addition, the TCEQ has jurisdiction over wastes generated at facilities where materials, processes, and equipment associated with oil and gas industry operations are researched, developed, designed, and manufactured. However, wastes generated from tests of materials, processes, and equipment at field sites are under the jurisdiction of the RRC.

(B) The TCEQ also has jurisdiction over waste generated at commercial service company facilities operated by persons providing equipment, materials, or services (such as drilling and work over rig rental and tank rental; equipment repair; drilling fluid supply; and acidizing, fracturing, and cementing services) to the oil and gas industry. These wastes include the following wastes when they are generated at commercial service company facilities: empty sacks, containers, and drums; drum, tank, and truck rinsate; sandblast media; painting wastes; spent solvents; spilled chemicals; waste motor oil; and unused fracturing and acidizing fluids.

(C) The term "commercial service company facility" does not include a station facility such as a warehouse, pipeyard, or equipment storage facility belonging to an oil and gas operator and used solely for the support of that

operator's own activities associated with the exploration, development, or production activities.

(D) Notwithstanding subparagraphs (A) - (C) of this paragraph, the RRC has jurisdiction over disposal of oil and gas wastes, such as waste drilling fluids and NORM-contaminated pipe scale, in volumes greater than the incidental volumes usually received at such facilities, that are managed at commercial service company facilities.

(E) The RRC also has jurisdiction over wastes such as vacuum truck rinsate and tank rinsate generated at facilities operated by oil and gas waste haulers permitted by the RRC pursuant to §3.8(f) of this title (relating to Water Protection).

(12) Mobile offshore drilling units (MODUs). MODUs are vessels capable of engaging in drilling operations for exploring or exploiting subsea oil, gas, or mineral resources.

(A) The RRC and, where applicable, the EPA, the U.S. Coast Guard, or the Texas General Land Office (GLO), have jurisdiction over discharges from an MODU when the unit is being used in connection with activities associated with the exploration, development, or production of oil or gas or geothermal resources, except that upon delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code, §26.131(a), the TCEQ shall assume RRC's authority under this subsection.

(B) The TCEQ and, where applicable, the EPA, the U.S. Coast Guard, or the GLO, have jurisdiction over discharges from an MODU when the unit is being serviced at a maintenance facility.

(C) Where applicable, the EPA, the U.S. Coast Guard, or the GLO has jurisdiction over discharges from an MODU during transportation from shore to exploration, development or production site, transportation between sites, and transportation to a maintenance facility.

(e) Interagency activities.

(1) Recycling and pollution prevention.

(A) The TCEQ and the RRC encourage generators to eliminate pollution at the source and recycle whenever possible to avoid disposal of wastes. Questions regarding source reduction and recycling may be directed to the TCEQ External Relations Division, or to the RRC. The TCEQ may require generators to explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the RRC at a facility regulated by the TCEQ; similarly, the RRC may explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the TCEQ at a facility regulated by the RRC.

(B) The TCEQ External Relations Division and the RRC will coordinate as necessary to maintain a working relationship to enhance the efforts to share information and use resources more efficiently. The TCEQ External Relations Division will make the proper TCEQ personnel aware of the services offered by the RRC, share information with the RRC to maximize services to oil and gas operators, and advise oil and gas operators of RRC services. The RRC will make the proper RRC personnel aware of the services offered by the TCEQ External Relations Division, share information with the TCEQ External Relations Division to maximize services to industrial operators, and advise industrial operators of the TCEQ External Relations Division services.

(2) Treatment of wastes under RRC jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K, (relating to Storage, Treatment, and Reuse Procedures for Petroleum-Substance Contaminated Soil).

(A) Soils contaminated with constituents that are physically and chemically similar to those normally found in soils at leaking underground petroleum storage tanks from generators under the jurisdiction of the RRC are eligible for treatment at TCEQ regulated soil treatment facilities once alternatives for recycling and source reduction have been explored. For the purpose of this provision, soils containing petroleum substance(s) as defined in 30 TAC §334.481 (relating to Definitions) are considered to be similar, but drilling muds, acids, or other chemicals used in oil and gas activities are not considered similar. Generators under the jurisdiction of the RRC must meet the same requirements as generators under the jurisdiction of the TCEQ when sending their petroleum contaminated soils to soil treatment facilities under TCEQ jurisdiction. Those requirements are in 30 TAC §334.496 (relating to Shipping Procedures Applicable to Generators of Petroleum-Substance Waste), except subsection (c) which is not applicable, and 30 TAC §334.497 (relating to Recordkeeping and Reporting Procedures Applicable to Generators). RRC generators with questions on these requirements should contact the TCEQ.

(B) Generators under RRC jurisdiction should also be aware that TCEQ regulated soil treatment facilities are required by 30 TAC §334.499 (relating to Shipping Requirements Applicable to Owners or Operators of Storage, Treatment, or Disposal Facilities) to maintain documentation on the soil sampling and analytical methods, chain-of-custody, and all analytical results for the soil received at the facility and transported off-site or reused on-site.

(C) The RRC must specifically authorize management of contaminated soils under its jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations.

(D) All waste, including treated waste, subject to the jurisdiction of the RRC and managed at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K will remain subject to the jurisdiction of the

RRC. Such materials will be subject to RRC regulations regarding final reuse, recycling, or disposal.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K.

(3) Processing, treatment, and disposal of wastes under RRC jurisdiction at facilities authorized by the TCEQ.

(A) As provided in this paragraph, waste materials subject to the jurisdiction of the RRC may be managed at solid waste facilities under the jurisdiction of the TCEQ once alternatives for recycling and source reduction have been explored. The RRC must specifically authorize management of wastes under its jurisdiction at facilities regulated by the TCEQ. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations. In addition, except as provided in subparagraph (B) of this paragraph, the concurrence of the TCEQ is required to manage "special waste" under the jurisdiction of the RRC at a facility regulated by the TCEQ. The TCEQ's concurrence may be subject to specified conditions.

(B) A facility under the jurisdiction of the TCEQ may accept, without further individual concurrence, waste under the jurisdiction of the RRC if that facility is permitted or otherwise authorized to accept that particular type of waste. The phrase "that type of waste" does not specifically refer to waste under the jurisdiction of the RRC, but rather to the waste's physical and chemical characteristics. Management and disposal of waste under the jurisdiction of the RRC is subject to TCEQ's rules governing both special waste and industrial waste.

(C) If the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization, individual written concurrences from the TCEQ shall be required to manage wastes under the jurisdiction of the RRC at TCEQ regulated facilities. Recommendations for the management of special wastes associated with the exploration, development, or production of oil, gas, or geothermal resources are found in TCEQ Regulatory Guidance document RG-3. (This is required only if the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization provided by the TCEQ.) To obtain an individual concurrence, the waste generator must provide to the TCEQ sufficient information to allow the concurrence determination to be made, including the identity of the proposed waste management facility, the process generating the waste, the quantity of waste, and the physical and chemical nature of the waste involved (using process knowledge and/or laboratory analysis as defined in 30 TAC Chapter 335, Subchapter R (relating to Waste Classification)). In obtaining TCEQ approval, generators may use their existing knowledge about the process or materials entering it to characterize their wastes. Material Safety Data Sheets, manufacturer's literature, and other documentation generated in conjunction with a particular process may be used. Process knowledge must be documented and submitted with the request for approval.

(D) Domestic septage collected from portable toilets at facilities subject to RRC jurisdiction that is not mixed with other waste materials may be managed at a facility permitted by the TCEQ for disposal, incineration, or land application for beneficial use of such domestic septage waste without specific authorization from the TCEQ or the RRC. Waste sludge subject to the jurisdiction of the RRC may not be applied to the land at a facility permitted by the TCEQ for the beneficial use of sewage sludge or water treatment sludge.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities under the jurisdiction of the TCEQ. If a receiving facility requires a TCEQ waste code for waste under the jurisdiction of the RRC, a code consisting of the following may be provided:

(i) the sequence number "RRCT";

(ii) the appropriate form code, as specified in 30 TAC Chapter 335, Subchapter R, §335.521, Appendix 3 (relating to Appendices); and

(iii) the waste classification code "H" if the waste is a hazardous oil and gas waste, or "R" if the waste is a nonhazardous oil and gas waste.

(F) If a facility requests or requires a TCEQ waste generator registration number for wastes under the jurisdiction of the RRC, the registration number "XXXRC" may be provided.

(G) Wastes that are under the jurisdiction of the RRC need not be reported to the TCEQ.

(4) Management of nonhazardous wastes under TCEQ jurisdiction at facilities regulated by the RRC.

(A) Once alternatives for recycling and source reduction have been explored, and with prior authorization from the RRC, the following nonhazardous wastes subject to the jurisdiction of the TCEQ may be disposed of, other than by injection into a Class II well, at a facility regulated by the RRC; bioremediated at a facility regulated by the RRC (prior to reuse, recycling, or disposal); or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous wastes that are chemically and physically similar to oil and gas wastes, but excluding soils, media, debris, sorbent pads, and other clean-up materials that are contaminated with refined petroleum products.

(B) To obtain an individual authorization from the RRC, the waste generator must provide the following information, in writing, to the RRC: the identity of the proposed waste management facility, the quantity of waste involved, a hazardous waste determination that addresses the process generating the waste and the physical and chemical nature of the waste, and any other information that the RRC may require. As appropriate, the RRC shall

reevaluate any authorization issued pursuant to this paragraph.

(C) Once alternatives for recycling and source reduction have been explored, and subject to the RRC's individual authorization, the following wastes under the jurisdiction of the TCEQ are authorized without further TCEQ approval to be disposed of at a facility regulated by the RRC, bioremediated at a facility regulated by the RRC, or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous bottoms from tanks used only for crude oil storage; unused and/or reconditioned drilling and completion/workover wastes from commercial service company facilities; used and/or unused drilling and completion/workover wastes generated at facilities where workers in the oil and gas exploration, development, and production industry are trained; used and/or unused drilling and completion/workover wastes generated at facilities where materials, processes, and equipment associated with oil and gas exploration, development, and production operations are researched, developed, designed, and manufactured; unless other provisions are made in the underground injection well permit used and/or unused drilling and completion wastes (but not workover wastes) generated in connection with the drilling and completion of Class I, III, and V injection wells; wastes (such as contaminated soils, media, debris, sorbent pads, and other cleanup materials) associated with spills of crude oil and natural gas liquids if such wastes are under the jurisdiction of the TCEQ; and sludges from washout pits at commercial service company facilities.

(D) Under Texas Water Code, §27.0511(g), a TCEQ permit is required for injection of industrial or municipal waste as an injection fluid for enhanced recovery purposes. However, under §27.0511(h), the RRC may authorize a person to use nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals as an injection fluid for enhanced recovery purposes without obtaining a permit from the TCEQ. The use or disposal of radioactive material under this subparagraph is subject to the applicable requirements of Texas Health and Safety Code, Chapter 401.

(E) Under Texas Water Code, §27.026, by individual permit, general permit, or rule, the TCEQ may designate a Class II disposal well that has an RRC permit as a Class V disposal well authorized to dispose by injection nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals under the jurisdiction of the TCEQ. The operator of a permitted Class II disposal well seeking a Class V authorization must apply to TCEQ and obtain a Class V authorization prior to disposal of nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals. A permitted Class II disposal well that has obtained a Class V authorization from TCEQ under Texas Water Code, §27.026, remains subject to the regulatory requirements of both the RRC and the TCEQ. Nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals to be disposed by injection in a permitted Class II disposal well authorized by TCEQ as a Class V injection well remain subject to the requirements of the Texas Health and Safety Code, the Texas Water Code, and the TCEQ's rules. The RRC and the TCEQ may impose additional requirements or conditions to address the dual injection activity under Texas Water Code, §27.026.

(5) Drilling in landfills. The TCEQ will notify the Oil and Gas Division of the RRC and the landfill owner at the time a drilling application is submitted if an operator proposes to drill a well through a landfill regulated by the TCEQ. The RRC and the TCEQ will cooperate and coordinate with one another in advising the appropriate parties of measures necessary to reduce the potential for the landfill contents to cause groundwater contamination as a result of landfill disturbance associated with drilling operations. The TCEQ requires prior written approval before drilling of any test borings through previously deposited municipal solid waste under 30 TAC §330.15 (relating to General Prohibitions), and before borings or other penetration of the final cover of a closed municipal solid waste landfill under 30 TAC §330.955 (relating to Miscellaneous). The installation of landfill gas recovery wells for the recovery and beneficial reuse of landfill gas is under the jurisdiction of the TCEQ in accordance with 30 TAC Chapter 330, Subchapter I (relating to Landfill Gas Management). Modification of an active or a closed solid waste management unit, corrective action management unit, hazardous waste landfill cell, or industrial waste landfill cell by drilling or penetrating into or through deposited waste may require prior written approval from TCEQ. Such approval may require a new authorization from TCEQ or modification or amendment of an existing TCEQ authorization.

(6) Coordination of actions and cooperative sharing of information.

(A) In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the TCEQ at a facility permitted by the RRC, the TCEQ is responsible for enforcement actions against the generator or transporter, and the RRC is responsible for enforcement actions against the disposal facility. In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the RRC at a facility permitted by the TCEQ, the RRC is responsible for enforcement actions against the generator or transporter, and the TCEQ is responsible for enforcement actions against the disposal facility.

(B) The TCEQ and the RRC agree to cooperate with one another by sharing information. Employees of either agency who receive a complaint or discover, in the course of their official duties, information that indicates a violation of a statute, regulation, order, or permit pertaining to wastes under the jurisdiction of the other agency, will notify the other agency. In addition, to facilitate enforcement actions, each agency will share information in its possession with the other agency if requested by the other agency to do so.

(C) The TCEQ and the RRC agree to work together at allocating respective responsibilities. To the extent that jurisdiction is indeterminate or has yet to be determined, the TCEQ and the RRC agree to share information and

take appropriate investigative steps to assess jurisdiction.

(D) For items not covered by statute or rule, the TCEQ and the RRC will collaborate to determine respective responsibilities for each issue, project, or project type.

(E) The staff of the RRC and the TCEQ shall coordinate as necessary to attempt to resolve any disputes regarding interpretation of this MOU and disputes regarding definitions and terms of art.

(7) Groundwater.

(A) Notice of groundwater contamination. Under Texas Water Code, §26.408, effective September 1, 2003, the RRC must submit a written notice to the TCEQ of any documented cases of groundwater contamination that may affect a drinking water well.

(B) Groundwater protection letters. The RRC provides letters of recommendation concerning groundwater protection.

(i) For recommendations related to normal drilling operations, shot holes for seismic surveys, and cathodic protection wells, the RRC provides geologic interpretation identifying fresh water zones, base of usable-quality water (generally less than 3,000 mg/L total dissolved solids, but may include higher levels of total dissolved solids if identified as currently being used or identified by the Texas Water Development Board as a source of water for desalination), and include protection depths recommended by the RRC. The geological interpretation may include groundwater protection based on potential hydrological connectivity to usable-quality water.

(ii) For recommendations related to injection, the RRC provides geologic interpretation of the base of the underground source of drinking water. The term "underground source of drinking water" is defined in 40 Code of Federal Regulations §146.3 (Federal Register, Volume 46, June 24, 1980).

(8) Emergency and spill response.

(A) The TCEQ and the RRC are members of the state's Emergency Management Council. The TCEQ is the state's primary agency for emergency support during response to hazardous materials and oil spill incidents. The TCEQ is responsible for state-level coordination of assets and services, and will identify and coordinate staffing requirements appropriate to the incident to include investigative assignments for the primary and support agencies.

(B) Contaminated soil and other wastes that result from a spill must be managed in accordance with the governing statutes and regulations adopted by the agency responsible for the activity that resulted in the spill. Coordination of issues of spill notification, prevention, and response shall be addressed in the State of Texas Oil and Hazardous Substance Spill Contingency Plan and may be addressed further in a separate Memorandum of Understanding among these agencies and other appropriate state agencies.

(C) The agency (TCEQ or RRC) that has jurisdiction over the activity that resulted in the spill incident will be responsible for measures necessary to monitor, document, and remediate the incident.

(i) The TCEQ has jurisdiction over certain inland oil spills, all hazardous-substance spills, and spills of other substances that may cause pollution.

(ii) The RRC has jurisdiction over spills or discharges from activities associated with the exploration, development, or production of crude oil, gas, and geothermal resources, and discharges from brine mining or surface mining.

(D) If TCEQ or RRC field personnel receive spill notifications or reports documenting improperly managed waste or contaminated environmental media resulting from a spill or discharge that is under the jurisdiction of the other agency, they shall refer the issue to the other agency. The agency that has jurisdiction over the activity that resulted in the improperly managed waste, spill, discharge, or contaminated environmental media will be responsible for measures necessary to monitor, document, and remediate the incident.

(9) Anthropogenic carbon dioxide storage. In determining the proper permitting agency in regard to a particular permit application for a carbon dioxide geologic storage project, the TCEQ and the RRC will coordinate by any appropriate means to review proposed locations, geologic settings, reservoir data, and other jurisdictional criteria specified in Texas Water Code, §27.041.

(f) Radioactive material.

(1) Radioactive substances. Under the Texas Health and Safety Code, §401.011, the TCEQ has jurisdiction to regulate and license:

(A) the disposal of radioactive substances;

(B) the processing or storage of low-level radioactive waste or NORM waste from other persons, except oil and gas NORM waste;

(C) the recovery or processing of source material;

(D) the processing of by-product material as defined by Texas Health and Safety Code, §401.003(3)(B); and

(E) sites for the disposal of low-level radioactive waste, by-product material, or NORM waste.

(2) NORM waste.

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM waste that constitutes, is contained in, or has contaminated

oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM that is not oil and gas NORM waste.

(C) The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These non-disposal activities are under the jurisdiction of the Texas Department of State Health Services under Texas Health and Safety Code, §401.011(a).

(3) Drinking water residuals. A person licensed for the commercial disposal of NORM waste from public water systems may dispose of NORM waste only by injection into a Class I injection well permitted under 30 TAC Chapter 331 (relating to Underground Injection Control) that is specifically permitted for the disposal of NORM waste.

(4) Management of radioactive tracer material.

(A) Radioactive tracer material is subject to the definition of low-level radioactive waste under Texas Health and Safety Code, §401.004, and must be handled and disposed of in accordance with the rules of the TCEQ and the Department of State Health Services.

(B) Exemption. Under Texas Health and Safety Code, §401.106, the TCEQ may grant an exemption by rule from a licensing requirement if the TCEQ finds that the exemption will not constitute a significant risk to the public health and safety and the environment.

(5) Coordination with the Texas Radiation Advisory Board. The RRC and the TCEQ will consider recommendations and advice provided by the Texas Radiation Advisory Board that concern either agency's policies or programs related to the development, use, or regulation of a source of radiation. Both agencies will provide written response to the recommendations or advice provided by the advisory board.

(6) Uranium exploration and mining.

(A) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium exploration activities.

(B) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium mining, except for in situ recovery processes.

(C) Under Texas Water Code, §27.0513, the TCEQ has jurisdiction over injection wells used for uranium mining.

(D) Under Texas Health and Safety Code, §401.2625, the TCEQ has jurisdiction over the licensing of source material recovery and processing or for storage, processing, or disposal of by-product material.

(g) Effective date. This Memorandum of Understanding, as of its July 15, 2020, effective date, shall supersede the prior Memorandum of Understanding among the agencies, dated May 1, 2012.

Source Note: The provisions of this §3.30 adopted to be effective May 31, 1998, 23 TexReg 5427; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective August 30, 2010, 35 TexReg 7728; amended to be effective May 1, 2012, 37 TexReg 2385; amended to be effective July 15, 2020, 45 TexReg 4503.

§3.31 Gas Reservoirs and Gas Well Allowable

(a) General.

(1) Allowables of gas wells not currently assigned an allowable will not be made effective:

(A) prior to the well's completion or reclassification date; or

(B) more than 15 days prior to the date all reports or information necessary to the assignment of an allowable are received in the appropriate commission office.

(2) If a report or item of information necessary to the assignment of an allowable is not filed on time, there shall be a one-day allowable reduction for each day the report or information is late.

(b) Changes in gas well allowables.

(1) Changes in allowable of gas wells currently assigned an allowable will be effective on the date of the test or date of the change affecting the well's allowable (when the operator submits special tests or information), provided this is not more than 15 days prior to the date the special test or information is received in the appropriate Commission office.

(2) With respect to a multicompleted well, the allowable of the second and succeeding zones will be made effective no earlier than the date the last report or item necessary for the assignment of an allowable is received in the appropriate Commission office.

(3) When a well is recompleted as a gas well in a different field, any overproduction that has occurred in the old field must be made up before an allowable will be assigned in the new field.

(4) The maximum daily allowable for a horizontal drainhole gas well or a gas well in a designated unconventional fracture treated (UFT) field is set forth in §3.86(d)(4) and (5) of this title (relating to Horizontal Drainhole Wells).

(c) Requirements for gas wells in a field for which an allocation formula has been adopted.

(1) If acreage is a factor in the allocation formula, a certified plat showing the acreage assigned to the well for proration purposes shall be submitted. The plat must be accompanied by a statement that all of the acreage claimed can reasonably be considered productive of gas and that the distance limitations of the field rules have not been exceeded. If all of the acreage claimed is not contained in a single lease, a certificate of pooling authority must be submitted, on the appropriate commission form. If the distance limitations of the field rules are shown to have been exceeded, the plat must show the number of acres within and beyond the distance limitations. An operator may request an exception to the distance limitations which may be administratively approved by the commission or a commission designee if all the acreage can be considered productive. If approval of the request is declined or protest is received, the request may be set for hearing. If all of the acreage cannot be considered productive, the plat must also show the productive limit of the acreage. If a plat shows acreage in the unit in excess of the maximum number of acres permitted by the field rules, it will not be accepted.

(2) If bottom-hole or reservoir pressure is a factor in the allocation formula, it shall be submitted on the appropriate commission form and shall be measured at, or corrected to, the proper datum plane.

(3) If any other information, data or parameter is a factor in the allocation formula, it must be submitted on the appropriate commission form.

(d) Determining prorated reservoir allowable and lawful market demand.

(1) On or before the 25th day of each month, the commission will determine the lawful market demand for gas to be produced from each reservoir during the upcoming allowable month. The monthly reservoir allowable shall be equal to the lawful market demand for that reservoir. The lawful reservoir market demand for prorated reservoirs shall be equal to the adjusted reservoir market demand forecast adjusted by a forecast correction adjustment, and a commission adjustment (i.e., lawful reservoir market demand = adjusted reservoir market demand forecast + forecast correction adjustment + commission adjustment).

(A) Allowable month--The month during which allowables determined pursuant to this section will be effective.

(B) Adjusted reservoir market demand forecast--The sum of all operator reservoir market demand forecasts for a reservoir after any necessary downward adjustments have been made to individual operator reservoir market demand forecasts and optional operator forecasts so that no such forecast will exceed the total capability of the operator's wells for the reservoir during the allowable month.

(C) Operator reservoir market demand forecast--The sum of the operator's well forecasts for a reservoir determined by the commission pursuant to this subsection.

(i) The commission will determine a forecast for each well that will be active during the allowable month that:

(I) for prorated and limited wells is equal to the well's production during the same allowable month in the prior year; and

(II) for special or administrative special allowable wells is equal to the well's production during the most recently reported production month.

(ii) If the well had no reported production during the same allowable month in the prior year or if a special or administrative special allowable well had no reported production in the most recently reported production month, the forecast shall be equal to:

(I) the well's highest reported monthly production during any of the three most recently reported production months; or, if no production has been reported for those months;

(II) the well's capability.

(iii) Alternatively, the operator reservoir market demand forecast may be determined by an optional operator forecast.

(D) Optional operator forecast--The commission designated operator may file an optional market demand forecast for all of the operator's wells in the reservoir that is equal to the anticipated market demand for the production from the operator's wells in the field during the allowable month. The optional operator forecast for the operator's wells in the reservoir can be no greater than the total capability of the operator's wells or less than zero. An optional operator forecast must be filed by the 10th day of the month preceding the allowable month.

(E) Forecast correction adjustment--

(i) The February 1994 forecast correction adjustment shall be the reservoir market demand for November 1993 for all wells in a reservoir that are not administrative special allowable wells for February 1994, subtracted from the production reported for November 1993 for those wells;

(ii) The March 1994 forecast correction adjustment shall be the reservoir market demand for December 1993 for all wells in a reservoir that are not administrative special allowable wells for March 1994, subtracted from the production reported for December 1993 for those wells;

(iii) The April 1994 forecast correction adjustment shall be the reservoir market demand for January 1994 for

all wells in a reservoir that are not administrative special allowable wells for April 1994, subtracted from the production reported for January 1994 for those wells;

(iv) For May 1994 and subsequent months, the forecast correction adjustment shall be equal to the total reservoir production from the most recent reported month, minus (total adjusted reservoir market demand forecast for the production month + supplemental change adjustment for that month + commission adjustment for that month), minus (production from all special and administrative special allowable wells minus allowable assigned to those special wells for that month).

(F) Supplemental change adjustment--Any adjustment to the reservoir allowable that is necessary to account for an automatic allowable revision in a prior month, a change of well or well test status during a prior month, the provisions of a final order modifying field or well production status, or any other ministerial change.

(G) Commission adjustment--Any other adjustments to the adjusted reservoir market demand forecast that the commission determines are necessary.

(2) The commission may reject or modify any optional operator forecast if it determines that the forecast is inaccurate or being used to manipulate the allocation of gas rather than to determine the reasonable market demand.

(e) Well capability.

(1) No gas well shall be given an initial allowable in excess of its capability.

(A) Except as provided in subparagraphs (B) and (C) of this paragraph, a well's capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's highest monthly production during any of the three most recently reported production months.

(B) If a well is a special or an administrative special allowable well, its capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's most recently reported monthly production.

(C) If a well is new to a reservoir and has been active for less than six months, its capability shall be defined as the well's latest deliverability test on file with the commission.

(2) An operator may submit a substitute capability determination for any well in a prorated field that represents the maximum monthly production capability of the well under normal operating conditions for a specific six-month period.

(A) The determination may be made on the basis of a well test or other acceptable information by a registered professional engineer who certifies that the determination was made by the engineer or under the supervision of the engineer, and that the capability has been determined in accordance with generally accepted engineering practices. Alternatively, the substitute capability determination may be made by an independent tester on the basis of a well test conducted in accordance with §3.28(c) of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported) (Statewide Rule 28). The request for a substitute capability must be submitted on the appropriate form.

(B) The commission or a commission designee may reject any substitute capability determination for good cause.

(C) The capability determined pursuant to this paragraph shall be used as the well's capability for a period of six months from the effective date of the determination unless:

(i) the operator files a written request that the substitute capability determination be cancelled. If such a request is submitted, the substitute capability may be cancelled by the commission or commission designee; or

(ii) an affected person files a protest alleging, with specificity, the inaccuracy or invalidity of the determination. If a protest is filed, the commission may set the matter for hearing. A protested substitute capability determination shall be effective on the intended effective date, unless the commission orders otherwise. If the commission determines that the protested substitute capability was incorrect, appropriate allowable or status adjustments will be made for the affected well.

(f) Fields operating under statewide rules. A statewide prorated field is any gas field in which no special field rules have been adopted and in which at least one well in the field has a current reported deliverability test of greater than 250 Mcf a day. Daily allowable production of gas from individual wells in a statewide prorated field shall be determined by allocating the allowable production among the individual wells in the proportion that each well's deliverability (based on the latest deliverability test of record) bears to the summation of the most recent reported deliverability tests of all wells producing from the same field. Allocated allowables shall be subject to the well capability provisions of this section.

(g) Definitions of prorated and nonprorated wells and fields.

(1) A prorated well is a well for which an allowable is determined by an allocation formula.

(2) A nonprorated well is a well for which an

allowable is not determined by an allocation formula.

(3) A prorated field is a field that has two or more wells one of which is a prorated well.

(4) A nonprorated field is any field that is not a prorated field.

(5) Statewide Exempt Fields:

(A) A statewide exempt field is any gas field in which no special field rules have been adopted and in which no well in the field has a current reported deliverability test of greater than 250 Mcf per day. Wells in statewide exempt fields shall be assigned allowables equal to their capacity to produce but in no event greater than 250 Mcf per day.

(B) In fields where special field rules exist and no well has a current deliverability test of greater than 250 Mcf per day, an operator may request statewide exempt field status. The request may be granted administratively by the commission or commission designee if the applicant provides the commission with a declaration, signed by all operators, subject to the false filing penalties provided for in the Texas Natural Resources Code, §91.143, stating all operators in the field agree to exempt status. If declarations are not provided from all operators in the field or if the commission or commission designee declines to grant any request administratively, the applicant may request a hearing. If a notice of intent to appear in protest of the application has not been filed by five days before the date of the hearing, then there shall be a presumption that each well's first purchaser has a market for 100% of the well's deliverability as determined by the most recent deliverability tests on file with the Commission and that granting exempt status to the field will not harm correlative rights or cause waste and exempt status will be granted. Wells in exempt fields with special rules shall be assigned allowables equal to their capability to produce but in no event greater than 250 Mcf per day. If 250 Mcf per day is exceeded by any well, the field will be changed to the existing special field rule allocation. Reinstatement of allocation formula may be initiated by the commission designee, or by one of the operators in the field.

(6) A limited well is a nonprorated well in a prorated field (other than a special or administrative special allowable well) with an allowable set below the maximum allowable it would receive under the allocation formula. A limited well shall be assigned an allowable at the rate that the well is capable of producing as determined by subsection (e) of this section.

(7) A special allowable well is a nonprorated well granted a fixed allowable by the commission after notice and hearing.

(8) An administrative special allowable well is a nonprorated well that has been granted an allowable pursuant to subsection (k) of this section.

(9) The maximum allowable for a well is the largest allowable that can be assigned under applicable rules. For a limited well, the maximum allowable is the allowable the well would receive under the allocation formula. For a special allowable well, the maximum allowable is the allowable assigned pursuant to paragraph (7) of this subsection. For administrative special allowable wells, the maximum allowable is 100 Mcf/day for wells qualifying as administrative special wells under subsection (k)(1) of this section and is the allowable the well would receive under the allocation formula for wells qualifying as administrative special allowable wells under subsection (k)(2) of this section. Additionally, for administrative special allowable wells in prorated gas fields without special field rules, the maximum allowable is 250 Mcf a day. For a well in a one well field, the maximum allowable is the well's deliverability based on the latest deliverability test of record. For an associated gas well, the maximum allowable is the gas well allowable calculated by §3.49(b)(1) or (2) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49).

(h) Allowable adjustments and balancing provisions for nonprorated wells.

(1) A nonprorated well shall not be allowed to accumulate underproduction. However, a limited well shall be entitled to accumulate underage up to the well's capability each month.

(2) If the most recent production figures reported to the commission show a nonprorated well to be overproduced, the alllowable will be revised to cover overproduction that is in excess of the well's accumulated underproduction, up to the maximum allowable. A nonprorated well with accumulated overproduction will be assigned a supplemental allowable that will balance the accumulated overproduction or a supplemental allowable equal to the well's maximum allowable, whichever is smaller.

(3) The allowable for wells in nonprorated fields, except for special and administrative special allowable wells, shall be limited to the lesser of:

(A) the well's maximum allowable;

(B) the well's capability as determined by subsection (e) of this section.

(4) The initial allowable for special and administrative special allowable wells shall be the least of the well's:

(A) capability;

(B) its amount of production during the most recently reported production month; or

(C) the amount provided for by the allocation formula.

(i) Balancing provisions for overproduction and underproduction of gas for wells completed in prorated gas

fields.

(1) Balancing provisions for prorated fields. Except as provided in subsection (h) of this section or as necessary to prevent waste or protect correlative rights, balancing provisions will be applied for wells completed in prorated gas fields.

(2) Balancing periods. For the purpose of computing and balancing overproduction and underproduction in prorated gas fields, the dates 7 a.m., March 1, and 7 a.m., September 1, are to be known as balancing dates; and the six-month periods beginning 7 a.m., March 1, and ending 7 a.m., September 1, and beginning 7 a.m., September 1, and ending 7 a.m., March 1, will be considered as separate entities and will be known as "balancing periods."

(3) Balancing provision for 49(b) fields. The balancing provisions may be applied by commission action after notice and hearing to fields where the well allowables are determined by §3.49(b) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49(b)).

(4) Underproduction.

(A) If during the balancing period a prorated gas well or a limited well does not produce as much gas as is allocated to it by the commission, the operator of the well shall be permitted to carry such underproduction forward to the next succeeding balancing period as future allowable credit to be produced during that period.

(B) The amount of underproduction to be carried forward into any new balancing period as allowed production during such new balancing period shall consist of the actual underproduction that accrued in the balancing period immediately preceding such new balancing period; and the accumulative well status as to underproduction, will be adjusted on each balancing date accordingly. An operator may request that underproduction not balanced during a second balancing period be carried forward to subsequent balancing periods. The operator's request must include evidence of increased market demand that will allow underproduction to be produced in the subsequent balancing period. The request may be granted administratively by the commission or a commission designee if the request was filed no later than the last day of the balancing period following the date the underproduction is canceled, the operator has given at least 21 days notice to all other operators in the field and the first purchaser of gas from the subject well, and no protest to the request has been filed. The request may also be approved administratively if the operator provides written waivers of objection from all to whom notice would be given as an alternative to notice and absence of protest. If the commission or a commission designee declines to grant administratively the request, the operator may request a hearing.

(5) Overproduction.

(A) Subject to the following prescribed conditions, the operator of a gas well, may produce the well in excess of the monthly allowable allocated to the well. No well shall in any one month be produced at a rate in excess of its underproduction plus twice its monthly allowable without obtaining approval from the commission prior to the due date for the production report for the overproduced month. A well which is balanced or overproduced may not in any one month produce an amount in excess of twice its monthly allowable without obtaining approval from the commission prior to the due date for the production report for the overproduced month. A well which is balanced or overproduced will not be granted such authority for more than two months in any six month balancing period.

(B) A well overproduced as of a balancing date, which was also overproduced on the balancing date immediately preceding and remained overproduced for the entire period between the two balancing dates, shall be shut-in until the overproduction, existent as of the later of such two balancing dates, is made up. Upon request by an operator, the commission may grant authority to produce such a well at a fractional part of its monthly allowable (reduced rate) until its production and allowable are in balance. The commission or a commission designee may determine the permissible rate.

(C) If a protest is received or the commission declines to approve a request to produce at a reduced rate, the operator of a well which under the provisions of subparagraph (B) of this paragraph is required to be shut-in, may request a hearing before the commission to determine whether shutting-in the well would damage it. Notice of the hearing will be given to all operators in the field and the first purchaser of the subject well. If, after consideration of the evidence submitted at the hearing, the commission finds that the well would be damaged if shut-in, the commission may allow the overproduction charged against it to be made up at a lesser rate than it would be made up if the well were shut-in. The commission or a commission designee may determine the permissible rate pending the result of the hearing.

(D) Except where a well is shut-in to make up overproduction or is producing at a reduced rate, overproduction existent as of any balancing date shall be made up at any time during the next period; i.e., a specified fractional part of the overproduction need not be made up during each month of that balancing period, so long as all of such overproduction is made up during that balancing period.

(j) Suspension of allocation formula.

(1) The commission or a commission designee may administratively suspend the allocation formula for a particular gas field if:

(A) each operator from that field has a market, for 100% of the deliverability, as determined by the deliverability tests on file with the commission, for its respective wells; and

(B) all operators in the field consent to suspension of the formula.

(2) Suspension of the allocation formula may be initiated by the commission or a commission designee, or by one of the operators in the field. The commission or a commission designee will determine which fields are appropriate for suspension utilizing the criteria of paragraph (1) of this subsection. The allocation formula may be administratively suspended if the applicant provides the commission with a declaration, subject to the false filing penalties provided for in the Natural Resources Code, §91.143, from all operators in the field stating that they have a market for 100% of the deliverability of their wells. If the commission or a commission designee declines to administratively suspend the allocation formula, the applicant may request a hearing as provided for in paragraph (4) of this subsection.

(3) Reinstatement of the allocation formula may be initiated by the commission, commission designee, or by one of the operators in the field.

(A) If, for any month, the market for gas production from a well in a field with a suspended allocation formula is less than 100% of the well's deliverability as determined by the deliverability tests on file with the commission, the operator of the field must inform the commission or a commission designee; upon such notification, the commission or commission designee will, with prior notice to the operators in the field, reinstate the allocation formula.

(B) The allocation formula will be reinstated at the request of an operator from a field with a suspended allocation formula or at any time the commission deems reinstatement necessary to protect correlative rights or prevent waste.

(4) If the commission or a commission designee reinstates the allocation formula or denies a request to suspend or reinstate the allocation formula in a particular field, the applicant may request a hearing. In addition to the criteria set forth in paragraph (1) of this subsection, the commission will consider whether suspension or reinstatement is necessary to prevent waste or protect correlative rights. An applicant may also request a hearing when unable to obtain written consent from all operators in a field pursuant to subparagraph (1)(B) of this subsection.

(5) Suspension of the allocation formula will balance the field's production status at zero, and provide for a 100% capacity allowable.

(k) Administrative Special Allowable.

(1) A well which has a deliverability, capability, and six consecutive months of production of 100 Mcf per day or less, and the well is not producing in a 49(b) field, will be assigned an administrative special allowable pursuant to subsection (h) of this section. Additionally, a well which has a deliverability, capability, and six consecutive months of production of 250 Mcf a day or less, and the well is producing in a prorated field without special field rules, will be assigned an administrative special allowable pursuant to subsection (h) of this section.

(2) A well, other than an administrative special allowable well defined in paragraph (1) of this subsection, in a prorated field whose average monthly production during the last six consecutive months falls below the cutoff percentage (determined by the commission at the monthly statewide hearing) of the well's top allowable averaged over that six-month period, will be assigned an administrative special allowable pursuant to subsection (h) of this section. The initial cutoff percentage is 70% and will remain at 70% until changed in accordance with this subparagraph. Administrative special allowable wells under this subsection will remain administrative special allowable wells until:

(A) they overproduce the top allowable available under the applicable allocation formula; or

(B) they receive a substitute capability pursuant to subsection (e) of this section; or

(C) the commission resets the cutoff percentage below the well's average production level for the last six consecutive months.

Source Note: The provisions of this §3.31 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective September 20, 1993, 18 TexReg 5977; amended to be effective January 11, 1994, 19 TexReg 71; amended to be effective May 19, 1997, 22 TexReg 4065; amended to be effective October 20, 1997, 22 TexReg 10311; amended to be effective February 1, 2016, 41 TexReg 785.

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

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

(1) Fugitive emissions--Releases of gas from lease production, gathering, compression, or gas plant equipment components, including emissions from valve stems, pressure relief valves, flanges and connections, gas-operated valves, compressor and pump seals, pumping well stuffing boxes, casing-to-casing bradenheads subject to the provisions of §3.17 of this title (relating to Pressure on Bradenhead), pits, and sumps, that cannot reasonably be captured and sold or routed to a vent or flare.

(2) Gathering system--Facilities employed to collect, compress, and transport gas to another gas gathering system, a gas plant, compression facility, or transmission line.

(3) Lease production facilities--Production, separation, treating, compression, flowlines, storage, and other production handling equipment employed on a lease in the production of gas, condensate, and oil.

(4) Low pressure separator gas--Gas separated or liberated from a gas-liquid stream in a low pressure separation facility. Low pressure separation facilities

include but are not limited to separators, treaters, free water knockouts, and other associated equipment.

(5) Tank vapors--Gas which evolves from oil, condensate, or water when placed in a gunbarrel or storage tank.

(b) Activities authorized by this section may be subject to rules and regulations promulgated by the United States Environmental Protection Agency under the federal Clean Air Act or the Texas Commission on Environmental Quality under the Texas Clean Air Act.

(c) General Provisions. All gas from any oil well, gas well, gas gathering system, gas plant or other gas handling equipment shall be utilized for purposes and uses authorized by law, except as provided in this section. This section does not apply to gas transmission or gas distribution facilities or operations.

(d) Exempt Gas Releases.

(1) Releases of gas that are not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, are not required by the commission to be reported or charged against lease allowable production and are not subject to the remaining requirements of this section. Releases of gas exempt from the requirements of this section under this paragraph include, but are not limited to, the following:

(A) tank vapors from crude oil storage tanks, gas well condensate storage tanks, or salt water storage tanks, including makeup gas for gas blanket maintenance;

(B) fugitive emissions of gas;

(C) amine treater, glycol dehydrator flash tank and/or reboiler emissions;

(D) blowdown gas from flow lines, gathering lines, meter runs, pressurized vessels, compressors, or other gas handling equipment for construction, maintenance or repair;

(E) gas purged from compressor cylinders or other gas handling equipment for startup;

(F) gas released at a wellsite during drilling operations and prior to the completion date of the well, including gas produced during air or gas drilling operations or gas which must be separated from drilling fluids using a mud-gas separator, or mud-degasser; or

(G) gas released at a wellsite during initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(2) Notwithstanding the foregoing, the commission or the commission's delegate may require the flaring of releases of gas not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, if the commission or the commission's delegate determines that flaring is required for safety reasons.

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

(1) Except as otherwise provided in subsections (d), (f)(1)(B) and (C), (g)(2), or an exception granted under subsection (h) of this section, all gas releases of greater than 24 hours duration authorized under the provisions of this section shall be burned in a flare if the gas can be burned safely. All gas releases of 24 hours' duration or less authorized under the provisions of this section may be vented to the air if flaring is not required for safety reasons or by other regulation and the gas can be safely vented.

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

(3) An exception to the requirements of this subsection may be granted under subsection (h) by the commission or the commission's delegate to allow the venting of gas to the air for releases of greater than 24 hours' duration if the operator presents information that shows the gas cannot be both safely and continuously burned in a flare, and the gas can be safely vented.

(4) Notwithstanding the provisions of paragraph (1) of this subsection or an exception granted under subsection (h), the commission or the commission's delegate may require that the gas be flared if flaring is required for safety reasons.

(f) Gas Releases in Oil and Gas Production Operations.

(1) The following releases of gas resulting from routine oil and gas production operations are necessary in the efficient drilling and operation of oil and gas wells and are hereby authorized subject to the requirements of subsection (e) of this section. The released gas shall be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported and charged against lease allowable production.

(A) Gas may be released for a period not to exceed ten producing days after initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(B) Gas from a well that must be unloaded or cleaned-up to atmospheric pressure may be vented to the air for periods not to exceed 24 hours in one continuous event or a total of 72 hours in one calendar month.

(C) In the event of a full or partial shutdown by a gas

gathering system, compression facility, or gas plant, gas from a lease production facility served by that gas gathering system, compression facility or gas plant may be released for a period not to exceed 24 hours. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period, pending commission approval or denial of a request for an administrative exception under subsection (h) of this section. The operator shall file the request with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate.

(D) Hydrocarbon gas contained in the waste stream from a membrane unit or molecular sieve used to remove carbon dioxide, hydrogen sulfide, or other contaminants from a gas stream may be released, provided that at least 85% of the hydrocarbon gas in the inlet gas stream is recovered and directed to a legal use.

(E) Low pressure separator gas, not to exceed 15 mcfd of hydrocarbon gas per gas well or 50 mcfd of hydrocarbon gas per commission-designated oil lease or commingling point for commingled operations, may be released.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection subject to the requirements of subsection (h) to allow additional releases of gas if the operator of a well or production facility presents information to show the necessity for the release. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form and shall be charged to the operator's allowable production. Necessity for the release includes, but is not limited to, the following situations:

(A) Cleaning a well of solids or fluids or both for more than ten producing days following initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, or well maintenance or repair operations;

(B) Unloading excess formation fluid buildup in a wellbore for periods in excess of 24 hours in one continuous event or 72 hours total in one calendar month;

(C) Volumes of low pressure gas that can be measured with devices routinely used in oil and gas exploration, development, and production operations and that are not directed by an operator to a gas gathering system, gas pipeline, or other marketing facility, or other purposes and uses authorized by law due to mechanical, physical, or economic impracticability;

(D) For casinghead gas only, the unavailability of a gas pipeline or other marketing facility, or other purposes and uses authorized by law; or

(E) Avoiding curtailment of gas production which will result in a reduction of ultimate recovery from a gas well or oil reservoir.

(g) Gas releases from gas gathering system, gas plant or gas handling operations.

(1) The operator of a gas gathering system, gas plant, gas compressor facility or other gas handling equipment not directly associated with lease production of gas, shall not intentionally allow gas to be released for a period of more than 24 hours after the start of an upset condition. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form. The provisions of this subsection do not apply to accidental releases which are subject to or reported pursuant to any other commission rule.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection and allow additional releases of gas for a period greater than 24 hours if the operator presents information that shows the necessity for the release. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period pending commission consideration of a request for an administrative exception under subsection (h) of this section. The request for exception is to be filed with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate. The following are examples of situations that may qualify for an exception under this paragraph:

(A) gas gathering system or gas plant construction, repairs or maintenance;

(B) gas plant turnaround; or

(C) emergency situations.

(h) Exceptions. The commission or the commission's delegate may administratively grant an exception authorized by this section provided that the requirements of this subsection are met.

(1) The request for an exception shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception shall not exceed a period of 180 days.

(3) The 180-day limitation shall not apply for volumes of gas less than or equal to 50 mcf of hydrocarbon gas per day for each gas well, commission-designated oil lease, or commingled vent or flare point.

(4) Requests for exceptions for more than 180 days and for volumes greater than 50 mcf of hydrocarbon gas per day shall be granted only in a final order signed by the commission.

(5) A request for an exception to cover an operating emergency, system upset, or other unplanned condition may be submitted by facsimile transmission or other means, provided that an original signed request is accompanied by the fee required by subsection (h)(1) of this section and is received by the commission within three working days of the facsimile transmission request.

(6) Exceptions shall be issued to the operator of a gas well or commission-designated oil lease or commingling point for commingled operations and to the operator of a processing plant or other facility subject to this section.

(7) Exceptions are not transferable upon a change of operatorship. Operators shall have 90 days from the date of commission approval of a transfer of operatorship to review existing exceptions to this section and, if continuation of the exception is needed, to make application for a new exception. The existing exception and existing authority shall remain in effect during the 90-day review period. If an operator files an application and fee for a new exception before the 90-day review period expires and the 90-day review period expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

(8) One application for exception to the requirements of this section may be filed for multiple releases from gas wells, commission-designated oil leases, gas gathering systems, gas compressors or other gas handling facilities when the release of gas is the result of a full or partial shut-down of a gas gathering system, gas plant, gas compressor or other gas handling facility under subsection (f)(1)(C) or (g)(1). Each well, lease or facility must be clearly identified by the applicant and a single fee paid under §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(i) Renewal and Amendment of Exceptions.

(1) The commission or the commission's delegate may renew an exception authorized by this section. An administrative renewal by the commission's delegate may not exceed a period of 180 days.

(2) A renewal shall be based upon a showing by the operator of a well, lease, or other facility subject to this section, that the conditions for which the initial exception or latest renewal was granted have not significantly changed despite a good-faith attempt by the operator to direct the gas to or utilize the gas for purposes and uses authorized by law.

(3) An operator shall file an application and fee for renewal of an exception with the commission 21 days prior to expiration of the existing exception authority. The request for renewal shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(4) If an operator files an application, accompanied by the required fee, for renewal of an existing exception to the requirements of this section at least 21 days before the expiration of the existing exception and the existing authority expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

(5) The request by an operator to amend an existing exception will require a new application for exception if the amendment will result in a material change of the previously granted exception.

(6) Material changes include, but are not limited to, the following:

(A) Change of operator of the well or facility subject to this section; and

(B) An increase in volume of gas to be released or an extension of the duration of an exception greater than that provided for in subsection (h) of this section.

(j) Opportunity for hearing.

(1) An operator may request a hearing on any application for an exception or exception renewal required by this section.

(2) An operator may request a hearing on any request for administrative approval of an exception or exception renewal that has been denied by the commission or the commission's delegate.

Source Note: The provisions of this §3.32 adopted to be effective December 4, 1996, 21 TexReg 11367; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271.

§3.33 Geothermal Resource Production Test Forms Required

(a) A production test form, with all information requested thereon filled in, shall be filed in the district office not later than 10 days after the test is completed. Production operations shall not be commenced before the test form is filed and the commission grants authority to initiate operations.

(b) The initial production test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.33 adopted to be effective January 1, 1976.

§3.34 Gas To Be Produced and Purchased Ratably

(a) Definitions. The following words and terms, when used in this section and in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affiliate--A person or entity that owns, is owned by, or is under common ownership with another person or entity to the extent of 50% or more or that otherwise controls or is controlled by another person or entity. Affiliates of a common entity are also affiliates of each other. A person or entity that purchases gas solely for purposes other than resale shall not be considered an affiliate, and an interstate pipeline, as defined in the Natural Gas Policy Act of 1978, §2(15) (15 United States Code §3301 et seq.), shall not be considered an affiliate of an intrastate pipeline.

(2) Commission designee--A Railroad Commission employee authorized to act for the commission. Any authority given to a commission designee is also retained by the commission. Any action taken by the commission designee is subject to review by the commission.

(3) Downstream purchaser--One that purchases natural gas for resale and is not a first purchaser.

(4) First purchaser or initial purchaser--The first purchaser of natural gas produced from a well. A first purchaser and any affiliate of the purchaser that transports any natural gas it purchases from a well by use of the same pipeline system used by the first purchaser of which it is an affiliate shall be treated as a single first purchaser for purposes of ratability requirements; provided, however, that an affiliate that is purchasing and accepting deliveries pursuant to a special marketing program that is in compliance with this section, shall be treated as a separate first purchaser; and, provided further that the designation of such affiliate as a separate first purchaser is reviewable by the commission and may be disallowed upon a showing that the designation was for purposes of circumventing this section. Any affiliate may file forms in its own name.

(5) Pipeline system--A network of physically connected pipelines that are operated as a single unit under normal conditions.

(A) A first purchaser's pipeline system is that portion of a physical segment of a pipeline that the first purchaser owns.

(B) If a first purchaser does not own the pipeline it uses to transport its gas, the first purchaser's pipeline system shall include all the wells from which it purchases that are on the pipeline system of the transport pipeline.

(C) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by transporting on another pipeline gas that it purchases as a first purchaser if the first purchaser is also purchasing as a first purchaser from the same field and transporting on a pipeline that it owns.

(D) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by executing gas exchange agreements.

(E) Any of a first purchaser's pipeline systems which serve a common customer or common customers in a common geographic location shall be operated in a manner to avoid unjust or unreasonable discrimination in takes as between those systems.

(F) A first purchaser shall not segregate its physically connected pipelines that are capable of being operated as a single unit under normal conditions into two or more pipeline systems or designate a gathering system as a separate system for purposes of circumventing this section.

(6) Prorated gas field--A reservoir or field in which an allocation formula is in effect.

(b) General provisions. This section is promulgated to promote and maintain ratable production of natural gas and to require production in compliance with priority categories established by the commission for the purposes of preventing waste, including production in excess of market demand, protecting correlative rights, preventing discrimination, and conserving the natural resources of this state. An operator shall not produce in excess of its ratable share of the market demand as determined by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31). An operator shall produce ratably as set out in subsection (e) of this section and shall produce in compliance with subsection (i) of this section which establishes priority categories of natural gas. Because production is dictated by pipeline capacity and market demand, pipelines are an integral part of production regulation. The requirements imposed on pipelines by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) are enforced to assist in the regulation of production and provide the only method by which such production regulation can be enforced and market demand met as required by statutory law. A first purchaser shall not discriminate between different wells from which it purchases in the same field, nor shall it discriminate unjustly or unreasonably between separate fields. The provisions of this section requiring ratable production and purchasing of gas apply to purchase and production from wells from which a first purchaser is purchasing on its pipeline system.

(c) Designation of pipeline system. A first purchaser shall, on or before a date designated by the commission or a commission designee, designate its pipeline system(s) and shall identify its affiliates that use the same pipeline system, including an affiliate operating a special marketing program that is in compliance with subsection (k) of this

section. A pipeline system designation must identify the physical segment of pipeline that constitutes the pipeline system and identify by Railroad Commission of Texas lease and/or identification number and field the wells on that pipeline system from which the first purchaser is purchasing. A change in pipeline system designation is not required to add or delete well connections. The designation of a pipeline system cannot be changed by a first purchaser without prior approval by the commission or a commission designee. Approval of a change in pipeline system designation cannot be given without prior notice of the requested designation given by the first purchaser to affected operators of wells on the system(s) for which a change in designation is sought. A hearing to determine the proper designation of a first purchaser's pipeline system may be called by the commission, or may be requested by a first purchaser or by an operator filing a complaint. The burden of proof in the hearing shall be on the first purchaser.

(d) Operators who use produced gas. Any person who purchases natural gas at the wellhead, at a common point within a field or fields or at the outlet of a processing or treating plant must determine if it is the initial purchaser.

(e) Production guidelines. An operator shall produce without discrimination between its wells in the same field on the same first purchaser's pipeline system and without unjust or unreasonable discrimination between its wells in separate fields on the same first purchaser's pipeline system. An operator shall apportion a first purchaser's delivery requests ratably to its wells in each field on the same first purchaser's pipeline system without discrimination in the same manner as provided in this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) and shall not produce in excess of its ratable share of the market demand as its share is determined by those rules. An operator shall produce in compliance with the priority categories of gas production established by the commission in subsection (i) of this section.

(f) Purchases from different fields.

(1) In making purchases and accepting deliveries between fields, a first purchaser of natural gas that purchases and accepts delivery of gas from more than one field on its same pipeline system must accept from each field a consistent percentage of the portion of the aggregate deliverability as determined by the deliverability tests and total gas limits that it is entitled to purchase from all wells from which it purchases on its pipeline system, unless the purchaser can demonstrate a just and reasonable basis for discriminating between fields.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(g) Purchases within a field.

(1) In making purchases and accepting deliveries within fields, a first purchaser of natural gas that purchases and accepts delivery of gas from different gas wells in the same priority category (see subsection (i) of this section) in the same field on its same pipeline system shall purchase and accept from the wells from which it purchases in the field a consistent percentage of the portion that it is entitled to purchase of the maximum allowable that a well is entitled to under the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction to establish an appropriate pattern of purchases or acceptance of deliveries to restore ratability.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(3) Purchases and deliveries of casinghead gas shall be based on the well's gas limit as specified in §3.49 of this title (relating to Gas-Oil Ratio) (Statewide Rule 49) as provided in subsection (h) of this section. Overproduction and underproduction of gas is administered by the provisions of §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31). A first purchaser shall not reduce purchases from a limited well as described in §3.31(g)(5) until all prorated gas wells from which it purchases in the field connected to its same pipeline system are ratably reduced to the assigned allowable of the limited well. Below that point, purchases from all prorated wells and limited wells should be reduced ratably by purchasing and accepting delivery of the same percentage of the portion that it is entitled to purchase of the maximum allowable established for the well by the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction in establishing an appropriate pattern of purchases or acceptances of deliveries to restore ratability. When purchases of gas described in subsection (i)(2) or (5) of this section are to be reduced, they shall be reduced ratably within each priority category.

(h) Casinghead gas reductions. When purchases and deliveries of casinghead gas described in subsection (i)(1) or (3) of this section are to be reduced, each well's share of the reduction shall be calculated by multiplying the total reduction by the fractional share that each well's gas limit bears to the arithmetic sum of the aggregate gas limits of all wells in the field from which the first purchaser has been purchasing on its same pipeline system. In calculating its reduction of a well, a first purchaser shall use that portion of the gas limits that it is entitled to purchase. A well operating under net gas/oil ratio authority shall produce no more gas than its gas limit as it would be reduced by the previously mentioned

procedure absent the net gas/oil ratio authority.

(i) Priority categories. First purchasers of gas shall satisfy their pipeline system demand for gas by purchasing and accepting delivery of gas from the following priority categories in ascending numerical order. Lower priority category gas is gas from a higher numerical category. A first purchaser shall not within its pipeline system curtail gas from a priority category if the purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. A first purchaser's purchases and acceptance of delivery of first, second, or third priority category gas under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids, or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the purchaser, whether or not these purchases are made as a first purchaser, shall not be curtailed if the first purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. If curtailed, the curtailment must be ratable with like priority category gas which the first purchaser is purchasing and accepting delivery of from wells on its same pipeline system.

(1) First priority shall be given to casinghead gas produced from certified tertiary recovery projects approved by the commission and secondary recovery projects involving water injection, gas injection, or pressure maintenance approved by the commission to prevent waste.

(2) Second priority shall be given to gas from special allowable wells as defined in §3.31(g)(6) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) granted special allowable status after the effective date of this section to prevent physical waste. Wells classified as special allowable wells pursuant to notice and hearing prior to the effective date of this section shall be given second priority unless a new determination is made that the special allowable status is not necessary to prevent physical waste.

(3) Third priority shall be given to the remainder of casinghead gas so that gas produced in association with oil production shall not be wastefully vented and oil production shall not be unnecessarily curtailed. Gas recovered from a landfill or sewage process shall also be given third priority.

(4) Fourth priority shall be given to gas from wells classified under §3.49(b) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49), but only to the extent of one full allowable for multiple 49(b) wells.

(5) Fifth priority shall be given to gas from administrative special allowable wells as defined in §3.31(g)(7) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) to gas from special allowable wells as described in §3.31(g)(6) granted that status prior to the effective date of this section (see paragraph (2) of this subsection) without notice and hearing, and to gas from special allowable wells granted

that status by the commission subsequent to the effective date of this section after notice and hearing for other reasons than to prevent physical waste.

(6) Sixth priority shall be given to the remainder of gas well gas, including limited wells (see subsection (g) of this section).

(j) Prohibition against discriminating in favor of purchaser's own production. A first purchaser of natural gas may not discriminate between or against natural gas of a similar kind or quality in favor of its own production or production in which it may be directly or indirectly interested in whole or in part.

(k) Special marketing programs. If a first purchaser elects to qualify an affiliate as a separate first purchaser, the first purchaser may designate the affiliate as a special marketing program. The special marketing program must comply with the following with respect to the purchase and acceptance of delivery of natural gas.

(1) For purposes of this subsection, an affiliated first purchaser is the special marketing program purchaser's affiliate whose pipeline is being used to transport the gas in the special marketing program.

(2) Each and every special marketing program offer to purchase gas must be made without discrimination within a field and without unjust or unreasonable discrimination between fields to all operators for all wells on the pipeline system of the affiliated first purchaser from which the affiliated first purchaser has been purchasing and accepting delivery of gas as a first purchaser. The offer must also be made for all first, second, and third priority category gas on the affiliated first purchaser's pipeline system which it has been purchasing and accepting for delivery under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the affiliated first purchaser, whether or not those purchases were made as a first purchaser.

(3) It is unreasonably discriminatory, and therefore prohibited, for the offer to purchase gas in the special marketing program, or for any release of gas for sale in the special marketing program to require release of any claims under any existing contract or require modification of any existing contract provisions other than a release of the gas for sale in the special marketing program or a requirement of a volume-for-volume basis for gas taken in the special marketing program to be credited against the contract from which gas is released for sale in the special marketing program, if the credit provision is limited to the period of actual participation in the special marketing program. Nothing in this paragraph shall prohibit an operator of any well from offering terms inconsistent with these provisions. The making of an offer which is not accepted shall not affect rights under existing contracts.

(4) If a well producing priority category 1, 2, or 3 gas

is shut in or curtailed, and waste, as defined in the Texas Natural Resource Code, Title 3, is found by the commission to exist, neither a special marketing program purchaser nor its affiliated first purchaser may purchase lower priority category gas until all the priority Category 1, 2, and 3 gas is taken and resulting waste is prevented. The commission shall expedite determination of waste, and may enter an emergency, temporary, or interim order upon application and affidavit proof that waste is occurring. The application and affidavit proof must be accompanied by supporting documentation, including data on well performance, and a statement that the application and affidavit proof has been served on the first purchaser(s) of the subject well(s) and any affiliated special marketing program purchaser using the first purchaser(s) same pipeline system on or before the date the application and affidavit proof has been mailed or delivered to the commission, with the opportunity for the first purchaser to respond within five days of service or of commission receipt, whichever is latest.

(5) The affiliated first purchaser must continue in compliance with this section to purchase and accept delivery from the wells for which the offer was made and not accepted.

(6) With respect to the purchase of gas from those that accept an offer made pursuant to this subsection, the special marketing program purchaser must comply with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) as a separate first purchaser.

(7) It is not the objective of this subsection to abrogate any existing contract rights or obligations.

(l) Sellers' complaint procedure. Any operator or nonoperator that is denied by the first purchaser in violation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the opportunity to produce a well's ratable share of gas or opportunity for a well to participate in a special marketing program may file a complaint with the commission and request the commission to direct the first purchaser to end the discriminatory practices. A complainant may request a hearing regarding alleged discriminatory practices or to determine whether a first purchaser is or has, through gas exchange agreements or through actions of its affiliate(s), denied an operator a reasonable opportunity to market its gas.

(m) Purchasers' complaint procedure. If after reasonable notice by the purchaser, an operator fails to comply with a first purchaser's request to reduce production ratably in compliance with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the purchaser may file a complaint with the commission and request the commission to direct the operator to comply with the purchaser's requests to reduce production ratably. The complainant or the operator may request the commission to take further action, including setting the issue for hearing.

(n) Hardship exceptions. If the operation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) causes undue hardship, the commission may, after proper notice and hearing, grant an exception or take appropriate action, including action to prevent waste or protect correlative rights.

(o) Severability provisions. If any provision of this section or its application to any person or circumstance is held invalid, the invalidity shall not affect other provisions or applications of the section which can be given effect without the invalid provisions or appreciation, and the provisions of the section are declared to be severable.

Source Note: The provisions of this §3.34 adopted to be effective September 1, 1986, 11 TexReg 3691; amended to be effective March 2, 1987, 12 TexReg 536; amended to be effective September 8, 1987, 12 TexReg 2860; amended to be effective February 29, 1988, 13 TexReg 838; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.35 Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned

(a) Abandonment of radioactive source.

(1) Immediate notice of the loss of a radioactive source shall be filed by the operator with the commission designating the location, by county, survey name and abstract number, lease name and well number, distances from survey boundaries and Lambert Coordinates.

(2) Procedures for recovery of the lost radioactive source will be furnished to the commission and such radioactive source shall not be declared abandoned until all reasonable effort has been expended to retrieve the tool.

(3) The operator shall erect, under supervision of the commission, a standardized permanent surface marker as a visual warning to any person who may reenter the hole for any reason, showing that it contains a radioactive source. This marker shall contain the following information: well name, commission number, surface location, name of the operator, name of the lease, the source or material abandoned in the well, the total depth of the well, the depth at which the source is abandoned, the plug back depth, the date of the abandonment of the source, the activity of the source, and a warning not to drill below the plug back depth.

(b) Abandonment procedures.

(1) Wells in which radioactive sources are abandoned shall be mechanically equipped so as to prevent either

accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources abandoned in the bottom of the well shall be covered with a substantial standard color dyed (red iron oxide) cement plug on top of which a whipstock or other approved deflection device shall be set. The dye is to alert the reentry operator prior to encountering the source.

(B) Upon abandoning the well in which a logging source has been cemented in place behind a casing string above total depth, a standard color dyed cement plug shall be placed opposite the abandoned source and a whipstock or other approved deflection device placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subparagraphs (A) and (B) of this paragraph, he shall seek commission approval to an alternate abandonment procedure.

(D) When a logging source must be abandoned in a producing zone, a standard color dyed cement plug shall be set and a whipstock or other approved deflection device placed above to direct the sidetrack at least 15 feet away from the source.

(2) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque shall be attached to the top of the casing left in the hole in such a manner that reentry cannot be accomplished without disturbing the plaque. This plaque shall serve as a visual warning to any person reentering the hole that a radioactive source has been abandoned in place in the well. The plaque shall contain the trefoil radiation symbol with a radioactive warning and shall be constructed of a long-lasting material such as monel, stainless steel, or brass, in accordance with specifications established by the commission. The plugging report filed with the commission shall identify the well as an abandoned radioactive source well, and shall show compliance with the procedures required by this section.

(3) The commission will maintain a current listing of all abandoned radioactive source wells, and each district office will keep such a list for radioactive source wells in that district.

Source Note: The provisions of this §3.35 adopted to be effective January 1, 1976.

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

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

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

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

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

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the

designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: $x = [(1.589)(\text{mole fraction } H_2S)(Q)]$ to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: $x = [(0.4546)(\text{mole fraction } H_2S)(Q)]$ to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current

adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard 253.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in

drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

(ii) Other materials and equipment (including materials and equipment used in drilling and workover operations) which are not included within the provision of clause (i) of this subparagraph may be used for hydrogen sulfide service provided:

(I) such materials and equipment are proved, as the result of advancements in technology or as the result of control and knowledge of operating conditions (such as temperature and moisture content), to be suitable for the use intended and where such usage is technologically acceptable as good engineering practice; and

(II) the commission has approved the use of said materials and equipments for the specific uses after written application.

(iii) Existing facilities (including materials in present common usage for drilling and workover operations in hydrogen sulfide areas) which are in operation prior to the effective date of this section, and where there has been no failure of existing equipment attributed to sulfide stress cracking, shall satisfy the requirements of this section.

(iv) In the event of a failure of any element of an existing system as the result of hydrogen sulfide stress cracking, the compliance status of the system shall be determined by the commission after the operator has submitted to the commission a detailed written report on the failure.

(7) All operations subject to subsection (a) of this section shall be subject to the additional control and equipment safety provision, paragraph (8) of this subsection, and the contingency plan provision, paragraph (9) of this subsection, if any of the following conditions apply:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road;

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(8) Control and equipment safety provision. Operators subject to this provision shall install safety devices and maintain them in an operable condition or shall establish safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. For intentional releases of a potentially hazardous volume of hydrogen sulfide gas, the gas must be flared unless permission to vent is obtained from the commission or its delegate. Venting will be allowed only upon a showing that the venting will not pose an unreasonable risk of harm to the public.

(9) Contingency plan provision.

(A) All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before hydrogen sulfide operations are begun.

(B) The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(C) The contingency plan shall be activated prior to an intentional release, or immediately upon the detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(D) Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

(E) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(F) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(G) The plan shall include a call list which shall include the following as they may be applicable:

(i) local supervisory personnel;

(ii) county sheriff;

(iii) Department of Public Safety;

(iv) city police;

(v) ambulance service;

(vi) hospital;

(vii) fire department;

(viii) doctors;

(ix) contractors for supplemental equipment;

(x) district Railroad Commission office;

(xi) the appropriate regional office of the Texas Commission on Environmental Quality or its successor agencies;

(xii) other public agencies.

(H) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(I) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the commission in accordance with subparagraph (L) of this paragraph.

(J) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(K) The plan shall include provisions for advance briefing of the public within an area of exposure. Such advance briefing shall include the following elements:

(i) the hazards and characteristics of hydrogen sulfide;

(ii) the necessity for an emergency action plan;

(iii) the possible sources of hydrogen sulfide within the area of exposure;

(iv) instructions for reporting a gas leak;

(v) the manner in which the public will be notified of an emergency;

(vi) steps to be taken in case of an emergency.

(L) In the event of a high density of population, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the commission.

(M) The plan shall include additional support information, if applicable, such as:

(i) location of evacuation routes;

(ii) location of safety and life support equipment;

(iii) location of hydrogen sulfide containing facilities;

(iv) location of nearby telephones and/or other means of communication; and

(v) special instructions for conditions at a particular installation such as local terrain and the effect of various weather conditions.

(N) The Railroad Commission District Office shall be notified as follows if the contingency plan is activated:

(i) 12 hours in advance of an intentional release or as soon as a decision is made to release if such decision could not reasonably have been made more than 12 hours prior to the release;

(ii) immediately in the case of an accidental release;

(iii) as soon as possible before or after an unplanned intentional release made in an emergency situation to prevent a possible uncontrolled release.

(O) The retention of the contingency plan shall be as follows.

(i) The plan shall be available for commission inspection at the location indicated on the certificate of compliance.

(ii) The plan shall be retained at the location which lends itself best to activation of the plan.

(P) In the event that, due to particular situations, a contingency plan cannot be developed consistent with the provisions of this paragraph, relating to the contingency plan, then the operator may develop an adjusted plan to fit the situation, and submit same with the certificate of compliance. Approval of the certificate of compliance so submitted will constitute approval of the contingency plan.

(Q) The plan shall be kept updated to insure its current applicability.

(10) Injection provision.

(A) Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this provision unless first approved by the commission after public hearing:

(i) where injection fluid is a gaseous mixture, or would be a gaseous mixture in the event of a release to the atmosphere, and where the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area

except a public road; or, if the 500 ppm radius of exposure is in excess of 50 feet and includes any part of a public road; or if the 100 ppm radius of exposure is 3,000 feet or greater;

(ii) where the hydrogen sulfide content of the gas or gaseous mixture to be injected has been increased by a processing plant operation.

(B) Each project involving the injection of gas or gaseous mixtures containing hydrogen sulfide which does not require a public hearing prior to receiving commission approval specified in this provision shall nevertheless be subject to the other provisions of this section to the extent that such provisions are applicable to such project.

(11) In addition to any other requirements of this section, drilling and workover operations, and gasoline plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following.

(A) Protective breathing equipment shall be maintained in two or more locations at the site.

(B) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(C) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in concentrations that could be harmful shall be utilized at the site.

(12) Drilling provision. Drilling and workover operations where the 100 ppm radius of exposure includes a public area or is 3,000 feet or greater shall be subject to the following additional provisions.

(A) Protective breathing equipment shall be maintained at the well site and shall be sufficient to allow for well control operations.

(B) The operator shall provide a method of igniting the gas in the event of an uncontrollable emergency.

(C) The operator shall install a choke manifold, mud-gas separator, and flare line, and provide a suitable method for lighting the flare.

(D) Secondary remote control of blowout prevention and choke equipment to be located away from the rig floor at a safe distance from the wellhead.

(E) Drill stem testing of hydrogen sulfide zones is permitted only in daylight hours.

(F) The Railroad Commission district office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this provision.

(G) A certificate of compliance shall be required on each well subject to this provision even if well is located on certificated lease.

(H) Full compliance with all the requirements of this provision must be satisfied before the well is drilled to a depth that is within 1,000 feet of the hydrogen sulfide zone. Alternate depths may be approved in advance by the appropriate commission district office.

(I) API Publication RP-49 is referenced as a suggested guideline for drilling and workover of wells subject to this provision.

(J) Blowout preventers and well control systems shall be pressure tested at or near compliance depth or at depth of nearest bit change prior to reaching compliance depth. The appropriate Railroad Commission district office must be notified at least four hours prior to the test.

(13) Training requirement provision.

(A) Each operator whose operations contain hydrogen sulfide in excess of 100 ppm shall train its employees working in the affected areas in hydrogen sulfide safety.

(B) Each operator shall require all service companies working in affected areas to utilize only those service company personnel who have been trained in accordance with the provisions of subparagraphs (C) and (D) of this paragraph. Written certification to the operator by the service company that only those service company personnel who have been trained in accordance with the training requirement provision will be utilized in affected areas complies with this provision. For this provision, service company shall mean any company actually performing work at well sites, gasoline plant sites, or on pipelines, where such work could allow the escape of hydrogen sulfide gas.

(C) The training of all personnel working in the affected areas shall include the following elements:

(i) hazards and characteristics of hydrogen sulfide;

(ii) safety precautions;

(iii) operation of safety equipment and life support system.

(D) On-site supervisory personnel shall be additionally trained in the following:

(i) effect of hydrogen sulfide on metal components in the system;

(ii) corrective action and shutdown procedures, and when drilling a well, blowout prevention, and well control procedures;

(iii) must have full knowledge of the requirements of the contingency plan, when such plan is required.

(E) Training schedules and course outlines shall be provided to the commission personnel upon request for the purpose of commission review to determine compliance with the provisions of subparagraphs (C) and (D) of this paragraph.

(14) Accident notification. Operators shall immediately notify the appropriate Railroad Commission District Office of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident.

(d) Reports required.

(1) Certificate of compliance provision. A certificate of compliance shall be submitted for operations subject to any provision of this section. The following shall apply to the certificate of compliance provision of the section.

(A) The certificate of compliance shall certify that operator has complied or will comply with applicable provisions of this section.

(B) The certificate of compliance shall be filed in triplicate in the commission district office where the operation is located.

(C) The certificate of compliance shall certify that existing operations subject to this section to be in compliance will be in compliance as specified in an attached schedule, or, for new or modified facilities, will be in compliance upon completion.

(D) An approved certificate of compliance will permit an operator to perform all activities described in the certificate without additional filing of approval; provided that, consistent with subsection (c)(12)(G) of this section, a certificate of compliance will be required on each well subject to the provisions of subsection (c)(12)(G) of this section.

(E) A new or amended certificate of compliance shall be required if there is a change in public exposure caused by public infringement of an existing radius of exposure resulting in a change in the applicable provisions of this section, not described by the existing certificate. The operator shall file the new or amended certificate within 30 days after such infringement.

(F) A new or amended certificate of compliance shall be required if there is modification of an existing operation or facility which increases the radius of exposure in a public area, or results in a change in the applicable provisions of this section not described by the existing certificate. The operator shall file the new or amended certificate at least 30 days prior to initiating the operation or construction.

(G) The operator shall file a certificate of compliance 30 days prior to commencement of a drilling or workover operation on wells where a certificate of compliance is required for that well by provisions of this section (wells drilled on noncertificated leases or wells with a 100 ppm radius of exposure greater than 3,000 feet).

(H) In case of extenuating circumstances, an operator may file a certificate of compliance with an attached written explanation for those cases where waiver of 30-day prior filing is requested. In such cases, the approval of the certificate of compliance will constitute authority to proceed.

(I) The certificate of compliance shall be prepared and executed by a party who, through training and experience, is qualified to make such certification.

(J) The certificate of compliance will be in effect until conditions are altered in a manner that would require amending the "certificate." The operator shall notify the commission within 30 days following cessation or abandonment of operations in a certificated area.

(K) The certificate of compliance required by the provisions of this order for an existing system are due in the district office as soon as is reasonably possible, and no later than September 1, 1976, and as applicable for new or modified operations.

(L) A certificate of compliance may cover a single operation or multiple operations located in an area, a field, or a group of fields within a commission district. The description of the type of operation as indicated on the form must be sufficiently complete to the degree that it is obvious what element of an operation is to be covered by the certificate. All Railroad Commission identification numbers for each element of the system must be shown on the certificate and must be identified as to the type of operation.

(M) Certificates are nontransferable, and a new operator of a system or any acquired element of a system or operation shall be required to certificate that operation. Operator of a certificated system shall notify the commission in writing when the system or any operating part has been transferred to another operator. An amended certificate shall be required should any change occur that would add or delete a Railroad Commission identification number covered by the certificate.

(N) Each operator shall maintain a current master list of all his operations for which a certificate of compliance is in effect and shall submit such list for inspection upon request by the commission.

(2) Completion report provision.

(A) The operator shall report on the initial completion report for new oil or gas wells the hydrogen sulfide concentrations of the wellhead gas for all wells where the hydrogen sulfide concentration is equal to or exceeds 100 ppm.

(B) The drilling of a well in an area which would require the submission of a certificate of compliance (Form H-9) shall have noted on the drilling application (Form W-1) that such certification has been filed.

(3) Releases of, and accidents related to, hydrogen sulfide. The operator shall furnish a written report to the district office within ten days of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident, whether it be from an accidental or intentional release.

(e) Exception provision. Any application for exception to the provisions of this section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

Source Note: The provisions of this §3.36 adopted January 1, 1976; amended to be effective September 1, 1976, 1 TexReg 1517; amended to be effective September 15, 1985, 10 TexReg 2069; amended to be effective April 7, 1995, 20 TexReg 2285; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.37 Statewide Spacing Rule

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

(2) When an exception to this section is desired, application shall be made by filing the proper fee as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) and the appropriate form according to the instructions on the form, accompanied by a plat as described in subsection (c) of this section. A person acquainted with the facts pertinent to the application shall certify that all facts stated in it are true and within the knowledge of that person.

(A) When an exception to only the minimum lease-line spacing requirement is desired, the applicant shall file a list of the mailing addresses of all affected persons, who, for tracts closer to the well than the greater of one-half of the prescribed minimum between-well spacing distance or the minimum lease-line spacing distance, include:

(i) the designated operator;

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

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

(B) When an exception to the minimum between-well spacing requirement of this section is desired, the applicant is required to file the mailing addresses of those persons identified in subparagraph (A)(i)-(iii) of this paragraph for each adjacent tract and each tract nearer to the well than the greater of one-half the prescribed minimum between-well spacing distance or the minimum lease-line spacing.

(3) An exception may be granted pursuant to subsection (h)(2) of this section, or after a public hearing held after at least 10 days notice to all persons described in paragraph (2) of this subsection. At any such hearing, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to prevent the confiscation of property. For purposes of giving notice of an application for an exception, the commission will presume that every person described in paragraph (2) of this subsection will be affected by the application, unless the Oil and Gas Division director or the director's delegate determines they are unaffected. Such determination will be made only upon written request and a showing by the applicant that:

(A) competent, conclusive geological or engineering data indicate that no drainage of hydrocarbons from the particular tract(s) subject to the request will occur due to production from the applicant's proposed well; and

(B) notice to the particular operator(s), lessee(s) of record, or owner(s) of record of unleased mineral interest would be unduly burdensome or expensive.

(4) If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county where the well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(b) The distances mentioned in subsection (a) of this section are minimum distances to provide standard development on a pattern of one well to each 40 acres in areas where proration units have not been established.

(c) In filing an application for an exception to the distance requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the form a plat that:

(1) shows to scale the property on which the exception is sought; all other applied for, permitted, and completed oil, gas, or oil and gas wells in the same field and reservoir on said property; and all adjoining surrounding properties and completed wells in the same field and reservoir within the prescribed minimum between-well spacing distance of the applicant's well;

(2) shows the entire lease, pooled unit, or unitized tract indicating the names and offsetting properties of all affected offset operators;

(3) corresponds to the listing required under subsection (a)(2) of this section;

(4) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(d) In the interest of protecting life and for the purpose of preventing waste and preventing the confiscation of property, the commission reserves the right in particular oil, gas, and geothermal resource fields to enter special orders increasing or decreasing the minimum distances provided by this section.

(e) No well drilled in violation of this section without special permit obtained, issued, or granted in the manner prescribed in said section, and no well drilled under such special permit or on the commission's own order which does not conform in all respects to the terms of such permit shall be permitted to produce either oil, gas, or geothermal resources and any such well so drilled in violation of said section or on the commission's own order shall be plugged.

(f) No operator shall commence the drilling of a well, either on a regular location or on a Rule 37 exception location, until first having been notified by the commission that the regular location has been approved, or that the Rule 37 exception location has been approved. Failure of an operator to comply with this subsection will cause such well to be closed in and the holding up of the allowable of such well.

(g) Subdivision of property.

(1) In applying Rule 37 (Statewide Spacing Rule) of statewide application and in applying every special rule with relation to spacing in every field in this state, no subdivision of property made subsequent to the adoption of the original spacing rule will be considered in determining whether or not any property is being confiscated within the terms of such spacing rule, and no subdivision of property will be regarded in applying such spacing rule or in determining the matter of confiscation if such subdivision took place subsequent to the promulgation and adoption of the original spacing rule.

(2) Any subdivision of property creating a tract of such size and shape that it is necessary to obtain an exception to the spacing rule before a well can be drilled thereon is a voluntary subdivision and not entitled to a permit to prevent confiscation of property if it were either:

(A) segregated from a larger tract in contemplation of oil, gas, or geothermal resource development; or

(B) segregated by fee title conveyance from a larger tract after the spacing rule became effective and the voluntary subdivision rule attached.

(3) The date of attachment of the voluntary subdivision rule is the date of discovery of oil, gas, or geothermal resource production in a certain continuous reservoir, regardless of the subsequent lateral extensions of such reservoir, provided that such rule does not attach in the case of a segregation of a small tract by fee title conveyance which is not located in an oil, gas, or geothermal resource field having a discovery date prior to the date of such segregation.

(4) The date of attachment of the voluntary subdivision rule for multiple reservoir fields located in the same structural feature and separated vertically but not laterally (i.e., the multiple reservoirs overlap geographically at least in part), shall be the same date as that assigned to the earliest discovery well for such multiple reservoir structure.

(5) If a newly discovered reservoir is located outside the then productive limits of any previously discovered reservoirs and is classified by the commission as a newly discovered field, then the date of discovery of such newly found reservoir remains the date of attachment for the voluntary subdivision rule, even though subsequent development may result in the extension of such newly discovered reservoir until it overlies or underlies older reservoirs with prior discovery dates.

(6) The date of attachment of the voluntary subdivision rule for a reservoir that has been developed through expansion of separately recognized fields into a recognized single reservoir and is merged by commission order is the earliest discovery date of production from such merged reservoir, and that date will be used subsequent to the date of merger of the fields into a single field.

(7) The date of attachment of the voluntary subdivision rule for a reservoir under any special circumstance which the commission deems sufficient to provide for an exception may be established other than as prescribed in this section, so that innocent parties may have their rights protected.

(h) Exceptions to Rule 37.

(1) An order granting exception to Rule 37 wherein protest is had shall carry as its last paragraph the following language: It is further ordered by the commission that this order shall not be final until 20 days after it is actually mailed to the parties by the commission; provided that if a motion for rehearing of the application is filed by any party at interest within such 20-day period, this order shall not become final until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the commission. Permits issued pursuant to paragraph (2) of this subsection shall be issued without the 20-day waiting period.

(2) The director of the Oil and Gas Division or a delegate of the director may issue an exception permit for drilling, deepening, or additional completion,

recompletion, or reentry in an existing well bore if:

(A) a notice of at least 10 days has been given, and no protest has been made to the application; or

(B) written waivers of objection are received from all persons to whom notice would be given pursuant to subsection (a)(2) of this section.

(3) Applications filed for drilling, deepening, or additional completion, recompletion, or reentry will be processed and permit issued in accordance with this regulation, subject to the commission's discretion to set any application for hearing. If the director or a delegate of the director declines to grant an application, the operator may request a hearing.

(i) Rule 37 permits.

(1) Unless otherwise specified in a permit or in a final order granting an exception to this section, permits issued by the commission for completions requiring an exception to this section shall expire two years from the effective date of the permit unless drilling operations are commenced in good faith within the two-year permit period. The permit period will not be extended.

(2) So long as a Rule 37 exception is in litigation, the two-year permit period will not commence. On final adjudication and decree from the last court of appeal the two-year permit period will commence, beginning on the date of final decree.

(j) Once an application for a spacing exception has been denied, no new application shall be entertained except on changed conditions. Changed conditions in the commission's administration of its Spacing Rule 37 and amendments thereto applicable to the various special fields and reservoirs of Texas and in passing upon applications for permits under said rule and amendments shall include, among other things, the following.

(1) Any material changes in the physical conditions of the producing reservoir under the tract under consideration or under the area surrounding said tract which would materially affect the recovery of oil, gas, or geothermal resource from the given tract.

(2) Any material changes in the distribution or allocation of allowable production in the area surrounding the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(3) Any additional permits granted by the commission for wells drilled in the area surrounding or on offset tracts to the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(4) Any additional facts or evidence thereof materially affecting or tending to affect the recovery of oil, gas, or geothermal resource from the applicant's tract, or the property rights of applicant, which were not known of and considered by the commission at any previous hearing or application thereon.

(k) Exceptions to Statewide Rule 37 apply to the total depth for which the permit is granted or if special field rules are applicable, an exception to the spacing rule shall be granted only for the reservoir or reservoirs or applicable depth to which the well is projected. Subsequent recompletion of the well to reservoirs other than that covered by the permit issued would be granted only after the filing and processing of a new application.

(l) Salt dome oil or gas fields.

(1) The provisions of this section shall not apply to certain approved salt dome oil or gas fields. An application for classification as a salt dome oil or gas field shall include the following:

(A) geological evidence proving that an oil or gas field is a piercement-type salt dome, that faulting has caused the producing formation to be at a 45 angle or greater, and that each well is likely to be completed in a separate reservoir;

(B) establishment, by plat or otherwise, of the probable productive limits of the salt dome area;

(C) certification that notice of the application for salt dome classification with evidence included has been given to all operators in the field or, if a new field, in accordance with subsection (a)(2) of this section; and

(D) a list of persons notified and the date notice was mailed.

(2) The director of the Oil and Gas Division, or the director's delegate, may administratively grant an application for salt dome classification if the evidence proves that the oil or gas field is a salt dome.

(3) The operator may request a hearing if the director of the Oil and Gas Division, or the director's delegate, declines to approve an application. If an application is protested within 10 days of notice, it will be set for hearing. After hearing, the examiner shall recommend final commission action.

(4) The amendment providing for administrative approval of salt dome oil and gas fields does not alter the status of those fields previously approved and listed in this section.

(m) Wells that were deviated, whether intentionally or otherwise, prior to April 1, 1949, and are bottomed on the lease where permitted, are legal wells. The Rule 37 department will develop the record in each reapplication for such deviated wells so that the commission can determine the condition of each such well. The following will be adduced from sworn testimony and authenticated

data at each such hearing.

(1) That such well was deviated before April 1, 1949. Proof of completion of the well prior to that date and its subsequent producing status is not adequate proof of deviation.

(2) That such well was completed on the lease where the surface location was permitted. Such bottom hole location must be proven by the submission of an acceptable authenticated directional survey.

(3) That such bottom hole location is one that either is not in direct violation of a condition or limitation placed in the permit to drill, or is not in violation of a specific commission order. Example: Denial order for a Rule 37 application for a comparable location.

(4) That the present operator of such well or its predecessor has not filed either a false inclination or a false directional survey with the commission.

(5) A well that is either bottomed off the lease, deviated after April 1, 1949, drilled in direct violation of a specific condition or limitation placed in the Rule 37 permit, or is in violation of a specific commission order, is an illegal well and it shall not be permitted, and such well where permit is refused shall not be considered a replaceable well under commission replacement-well regulation.

(6) The provisions of this section do not preclude an operator from applying for approval of the bottom hole location of a deviated well as a reasonable location under the rules and regulations now applicable, provided, that such bottom hole location shall not be approved unless the applicant proves that a vertical projection of the permitted surface location for such well is within the productive limits of the reservoir.

Source Note: The provisions of this §3.37 adopted to be effective January 1, 1976; amended to be effective November 4, 1981, 6 TexReg 3911; amended to be effective May 7, 1982, 7 TexReg 1624; amended to be effective June 1, 1989, 14 TexReg 1586; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective September 15, 1997, 22 TexReg 8973; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective March 18, 2019, 44 TexReg 1437.

§3.38 Well Densities

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

(1) Commission designee--Director of the Oil and Gas Division or any Commission employee designated in writing by the director or the Commission.

(2) Drilling unit--The acreage assigned to a well for drilling purposes.

(3) Proration unit--The acreage assigned to a well for the purpose of assigning allowables and allocating allowable production to the well.

(4) Substandard acreage--Less acreage than the smallest amount established for standard or optional drilling units.

(5) Surplus acreage--Substandard acreage within a lease, pooled unit, or unitized tract that remains unassigned after the assignment of acreage to each applied for, permitted, or completed well in a field, in an amount equaling or exceeding the amount established for standard or optional drilling units. Surplus acreage is distinguished from the term "tolerance acreage," in that tolerance acreage is defined in context with proration regulation, while surplus acreage is defined by this rule only in context with well density regulation.

(6) Tolerance acreage--Acreage within a lease, pooled unit, or unitized tract that may be assigned to a well for proration purposes pursuant to special field rules in addition to the amount established for a prescribed or optional proration unit.

(b) Density requirements.

(1) General prohibition. No well shall be drilled on substandard acreage except as hereinafter provided.

(2) Standard units.

(A) The standard drilling unit for all oil, gas, and geothermal resource fields wherein only spacing rules, either special, country regular, or statewide, are applicable is hereby prescribed to be the following.

Spacing Rule	Acreage Requirement
(1) 150 - 300	02
(2) 200 - 400	04
(3) 330 - 660	10
(4) 330 - 933	20
(5) 467 - 933	20
(6) 467 - 1200	40
(7) 660 - 1320	40

(B) The spacing rules listed in subparagraph (A) of this paragraph are not exclusive. If any spacing rule not listed in subparagraph (A) of this subsection is brought to the attention of the commission, it will be given an appropriate acreage assignment.

(c) Development to final density. An application to drill a well for oil, gas, or geothermal resource on a drilling unit composed of surplus acreage, commonly referred to as the "tolerance well," may be granted as regular when the operator seeking such permit certifies to the commission in a prescribed form the necessary data to show that such permit is needed to develop a lease, pooled unit, or unitized tract to final density, and only in the following circumstances:

(1) when the amount of surplus acreage equals or exceeds the maximum amount provided for tolerance acreage by special or county regular rules for the field, provided that this paragraph does not apply for a lease, pooled unit, or unitized tract that is completely developed with optional units and the special or county regular rules for the field do not have a tolerance provisions expressly made applicable to optional proration units;

(2) if the special or county regular rules for the field do not have a tolerance provision expressly made applicable to optional proration units, when the amount of surplus acreage equals or exceeds one-half of the smallest amount established for an optional drilling unit; or

(3) if the applicable rules for the field do not have a tolerance provision for the standard drilling or proration unit, when the amount of surplus acreage equals or exceeds one-half the amount prescribed for the standard unit.

(d) Applications involving the voluntary subdivision rule.

(1) Density exception not required. An exception to the minimum density provision is not required for the first well in a field on a lease, pooled unit, or unitized tract composed of substandard acreage, when the leases, or the drillsite tract of a pooled unit or unitized tract:

(A) took its present size and shape prior to the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)); or

(B) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)) and was not composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(2) Density exception required. An exception to the density provision is required, and may be granted only to prevent waste, for a well on a lease, pooled unit, or unitized tract that is composed of substandard acreage and that:

(A) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to the Statewide Spacing Rule)); and

(B) was composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(3) Unit dissolution.

(A) If two or more separate tracts are joined to form a unit for oil or gas development, the unit is accepted by the Commission, and the unit has produced hydrocarbons in the preceding twenty (20) years, the unit may not thereafter be dissolved into the separate tracts with the rules of the commission applicable to each separate tract if the dissolution results in any tract composed of substandard acreage for the field from which the unit produced, unless the Commission approves such dissolution.

(B) The Commission shall grant approval only after application, notice, and an opportunity for hearing. The applicant seeking the unit dissolution shall provide a list of the names and addresses of all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract at the time the application is filed. The Commission shall give notice of the application to all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract. Additionally, if one or more wells on the unitized tract has produced from the field within the 12-month period prior to the application, the applicant shall include on the list all affected persons described in subsection (h)(1)(A) of this section, and the Commission shall give notice of the application to these affected persons.

(C) A Commission designee may grant administrative approval if the Commission designee determines that granting the application will not result in the circumvention of the density restrictions of this section or other Commission rules, and if either:

(i) written waivers are filed by all affected persons; or

(ii) no protest is filed within the time set forth in the notice of application.

(e) Application involving unitized areas with entity for density orders. An exception to the minimum density provision is not required for a well in a unitized area for which the commission has granted an entity for density order, if the sum of all applied for, permitted, or completed producing wells in the field within the unitized area, multiplied by the applicable density provision, does not exceed the total number of acres in the unitized area. The operator must indicate the docket number of the entity for density order on the application form.

(f) Exceptions to density provisions authorized. The Commission, or Commission designee, in order to prevent waste or, except as provided in subsection (d)(2) of this section, to prevent the confiscation of property, may grant exceptions to the density provisions set forth in this section. Such an exception may be granted only after notice and an opportunity for hearing.

(g) Filing requirements.

(1) Application. An application for permit to drill shall include the fees required in §3.78 of this title (relating to Fees and Financial Security Requirements) and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Plat. When filing an application for an exception to the density requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the application a plat that:

(A) depicts the lease, pooled unit, or unitized tract, showing thereon the acreage assigned to the drilling unit for the proposed well and the acreage assigned to all current applied for, permitted, or completed oil, gas, or oil and gas wells in the same field or reservoir which are located within the lease, pooled unit, or unitized tract;

(B) on large leases, pooled units, or unitized tracts, if the established density is not exceeded as shown on the face of the application, outlines the acreage assigned to the well for which the permit is sought and the immediately adjacent wells on the lease, pooled unit, or unitized tract;

(C) on leases, pooled units, or unitized tracts from which production is secured from more than one field, outlines the acreage assigned to the wells in each field that is the subject of the current application;

(D) corresponds to the listing required under subsection (g)(1)(A) of this section.

(E) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(3) Substandard acreage. An application for a permit to drill on a lease, pooled unit, or unitized tract composed of substandard acreage must include a certification in a prescribed form indicating the date the lease, or the drillsite tract of a pooled unit or unitized tract, took its present size and shape.

(4) Surplus acreage. An application for permit to drill on surplus acreage pursuant to subsection (c) of this section must include a certification in a prescribed form indicating the date the lease, pooled unit, or unitized tract took its present size and shape.

(5) Certifications. Certifications required under paragraphs (3) and (4) of this subsection shall be filed on Form W-1A, Substandard Acreage Certification.

(A) The operator shall file the Form W-1A with the drilling permit application and shall indicate the purpose of filing. The operator shall accurately complete all information required on the form in accordance with instructions on the form.

(B) The operator shall list the field or fields for which the substandard acreage certification applies in the designated area on the form. If there are more than three fields for which the certification applies, the operator shall attach additional Forms W-1A and shall number the additional pages in sequence.

(C) The operator shall file the original Form W-1A with the Commission's Austin office and a copy with the appropriate district office, unless the operator files electronically.

(D) The operator or the operator's agent shall certify the information provided on the Form W-1A is true, complete, and correct by signing and dating the form, and listing the requested identification and contact information.

(E) Failure to timely file the required information on the appropriate form may result in the dismissal of the application.

(h) Procedure for obtaining exceptions to the density provisions.

(1) Filing requirements. If a permit to drill requires an exception to the applicable density provision, the operator must file, in addition to the items required by subsection (g) of this section:

(A) a list of the names and addresses of all affected persons. For the purpose of giving notice of application, the Commission presumes that affected persons include the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. The Commission designee may determine that such a person is not affected only upon written request and a showing by the applicant that:

(i) competent, convincing geological or engineering data indicate that drainage of hydrocarbons from the particular tracts subject to the request will not occur due to production from the proposed well; and

(ii) notice to the particular operators and unleased mineral interest owners would be unduly burdensome or expensive;

(B) engineering and/or geological data, including a written explanation of each exhibit, showing that the drilling of a well on substandard acreage is necessary to prevent waste or to prevent the confiscation of property;

(C) additional data requested by the Commission designee.

(2) Notice of application. Upon receipt of a complete application, the Commission will give notice of the application by mail to all affected persons for whom signed waivers have not been submitted. If, after diligent efforts, the applicant is unable to ascertain the name and

address of one or more persons required by this subsection to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county where the well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(3) Approval without hearing. If the Commission designee determines, based on the data submitted, that a permit requiring an exception to the applicable density provision is justified according to subsection (f) of this section, then the Commission designee may issue the exception permit administratively if:

(A) signed waivers from all affected persons were submitted with the application; or

(B) notice of application was given in accordance with this subsection and no protest was filed within 21 days of the notice; or

(C) no person appeared to protest the application at a hearing scheduled pursuant to paragraph (4)(A) of this subsection.

(4) Hearing on the application.

(A) If a written protest is filed within 21 days after the notice of application is given in accordance with paragraph (2) of this subsection, the application will be set for hearing.

(B) If the application is not protested and the Commission designee determines that a permit requiring an exception to the applicable density provision is not justified according to subsection (f) of this section, the operator may request a hearing to consider the application.

(i) Duration. A permit is issued as an exception to the applicable density provision shall expire two years from the effective date of the permit; unless drilling operations are commenced in good faith within the two year period.

(j) The requirements for density exceptions for wells in a designated unconventional fracture treated (UFT) field are set forth in §3.86(k) of this title (relating to Horizontal Drainhole Wells).

Source Note: The provisions of this §3.38 adopted to be effective November 1, 1989, 14 TexReg 5255; amended to be effective April 21, 1997, 22 TexReg 3404; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective February 13, 2002, 27 TexReg 906; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective February 1, 2016, 41 TexReg 785; amended to be effective March 18, 2019, 44 TexReg 1437 .

As in effect on 12/9/2024.

§3.39 Proration and Drilling Units: Contiguity of Acreage and Exception Thereto

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

Source Note: The provisions of this §3.39 adopted to be effective January 1, 1976.

§3.40 Assignment of Acreage to Pooled Development and Proration Units

(a) An operator may pool acreage, in accordance with appropriate contractual authority and applicable field rules, for the purpose of creating a drilling unit or proration unit by filing an original certified plat delineating the pooled unit and a Certificate of Pooling Authority, Form P-12, according to the following requirements:

(1) Each tract in the certified plat shall be identified with an outline and a tract identifier that corresponds to the tract identifier listed on Form P-12.

(2) The operator shall provide information on Form P-12, accurately and according to the instructions on the form.

(A) The operator shall separately list each tract committed to the pooled unit by authority granted to the operator.

(B) For each tract listed on Form P-12, the operator shall state the number of acres contained within the tract. The operator shall indicate by checking the appropriate box on Form P-12 if, within an individual tract, there exists a non-pooled and/or unleased interest.

(C) The operator shall state on Form P-12 the total number of acres in the pooled unit. The total number of acres in the pooled unit shall equal the sum of all acres in each tract listed. The total acreage shown on Form P-12 shall only include tracts in which the operator holds a leased or ownership interest in the minerals or other contractual authority to include the tract in the pooled unit.

(D) If a pooled unit contains more tracts than can be listed on a single Form P-12, the operator shall file as many additional Forms P-12 as necessary to list each pooled tract individually. The additional Forms P-12 shall be numbered in sequence.

(E) The operator shall provide the requested identification and contact information on Form P-12.

(F) The operator shall certify the information on Form P-12 by signing and dating the form.

(3) Failure to timely file the required information on the certified plat or Form P-12 may result in the dismissal of the W-1 application. "Timely" means within three months of the Commission notifying the operator of the need for additional information on the certified plat and/or Form P-12.

(4) The operator shall file Form P-12 and a certified plat in the following instances:

(A) with the drilling permit application when two or more tracts are joined to form a pooled unit for Commission purposes;

(B) with the initial completion report if any information reported on Form P-12 has changed since the filing of the drilling permit application;

(C) to designate a pooled unit formed after a completionr eport has been filed; or

(D) to designate a change in a pooled unit previously recognized by the Commission. The operator shall file any changes to a pooled unit in accordance with the requirements of §3.38(d)(3) of this title (relating to Well Densities).

(b) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest provided that total gross acreage in the tract is included for allocation purposes, and the certificate filed with the Commission shows that a certain undivided interest is outstanding in the tract. The Commission may not allow an operator to assign only the operator's undivided interest out of a basic tract where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains the development rights in the basic tract. If the development rights are exercised, the Commission grants authority to develop the basic tract, and the well is completed as a producing well on the basic tract, then the entire interest in the basic tract and any interest pooled with another tract shall be assigned to the well on the basic tract for allocation purposes. Splitting of an undivided interest in a basic tract between two or more wells on two or more tracts is not acceptable.

(d) Multiple assignment of acreage is not permitted, except as provided in subsection (e) of this section. Multiple assignment of acreage is defined as the assignment of the same surface acreage to more than one well in a field. However, this limitation shall not prevent the reformation of development or proration units so longas:

(1) no multiple assignment of acreage occurs; and

(2) such reformation does not violate other conservation regulations.

(e) In unconventional fracture treated (UFT) fields defined in §3.86 of this title (relating to Horizontal Drainhole Wells), multiple assignment of acreage is permissible as follows:

(1) Assignment of acreage to both a horizontal well and a vertical well for drilling and development or for allocation of allowable is permissible. The field density rules apply independently to horizontal wells and vertical wells. Acreage assigned to horizontal wells shall not count against acreage assigned to vertical wells, and acreage assigned to vertical wells shall not count against acreage assigned to horizontal wells.

(A) Acreage assigned to horizontal wells for drilling and development or for allocation of allowable shall be permissible so long as the horizontal well density complies with §3.38 of this title and/or special field rules, as applicable. For the purposes of this section, stacked lateral wells as defined in §3.86(a)(10)of this title are not considered assignment of acreage to multiplehorizontal wells.

(B) Acreage assigned to vertical wells for drilling and development or for allocation of allowable shall be permissible so long as the vertical well density complies with §3.38 of this title and/or special field rules, as applicable.

(2) Where ownership of the right to drill or produce from a tract in a UFT field is divided horizontally, acreage may be assigned to more than one well provided that the wells having the same wellbore profile are not completed in the same ownership interval. For purposes of this section "divided horizontally" means that ownership of the right to drill or produce has been separated into depth intervals defined by total vertical depth, depth relative to a specific geological contact, or some other discriminator. A tract may be "divided horizontally" even where one operator has the right to drill or produce multiple intervals on the same tract of land in the same field.

(A) To apply for multiple assignment of acreage under this subsection, the operator's drilling permit application shall indicate the upper and lower limits of the operator's ownership interval. The interval shown on the drilling permit application is measured as the total vertical depth from the surface.

(B) No more than 15 days prior to filing its drilling permit application, the applicant shall identify any well, including any wells permitted but not yet drilled or completed, that is located within one-half mile of the applicant's proposed wellbore between the first and last take points and, upon identification of all applicable wells, send written notice of its application to the P-5 address of record of the Commission-designated operator of the wells determined to fall within the one-half mile radius. The applicant shall attach to the notice a certified plat that clearly depicts the projected path of the wellbore and the one-half mile radius surrounding the wellbore from the first take point to the last take point. Copies of the notice, service list, and certified plat shall be filed with the drilling permit application.

(C) If any person entitled to notice under this subsection did not receive notice, that person may request a hearing. If the Commission determines at a hearing that the applicant did not provide the notice as required by this subsection, the Commission may cancel the permit.

(D) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the persons entitled to notice under this subsection, upon request, within 15 days of the applicant's receipt of a request.

(E) Where ownership of the right to drill or produce from a tract in a UFT field is divided horizontally, the field density rules for the field will apply separately to each ownership interval, such that proration units on a tract above and below a division of ownership are accounted for separately.

(F) Field rules that allow assignment of acreage to more than one well in UFT fields are superseded by this rule amendment, as of the effective date of this amendment, March 3, 2020. If, prior to the effective date of this amendment, an operator has assigned acreage to more than one well pursuant to previous field rules, such multiple assignment remains valid. After March 3, 2020, multiple assignment of acreage is not permissible unless the applicant complies with the requirements of this subsection. The Commission will not consider any applications for field rules regarding multiple assignment of acreage in UFT fields until two years after March 3, 2020.

(3) Upon request by the Commission, an operator shall provide non-confidential information verifying that the well was completed in the interval indicated on its drilling permit application.

(f) Upon an operator's written request and for good cause shown, the director or the director's delegate may resolve an existing instance of multiple assignment of acreage. If such a request is administratively denied, the operator shall have a right to request a hearing to review the denial.

(g) If an operator does not qualify for multiple assignment of acreage under subsection (e) of this section, acreage cannot be assigned to more than one well unless the operator is granted an exception after a public hearing held after notice to all persons described in paragraph (2) of this subsection.

(1) An operator applying for an exception must show:

(A) an exception is necessary to prevent waste, prevent confiscation, or protect correlative rights; and

(B) the wells are not completed in the same ownership interval.

(2) If an exception is sought for a well in a UFT field, the operator shall file with its application for an exception the names and mailing addresses of persons described in §3.86(k)(2), relating to Horizontal Drainhole Wells. If an exception is sought for any other well, the operator shall file with its application for an exception the names and mailing addresses of all the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. In the event the applicant is unable after due diligence to locate the whereabouts of any person to whom notice is required by this subsection, the applicant shall publish notice of this application pursuant to §1.43 of this title (relating to Notice by Publication).

(3) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the persons entitled to notice under this subsection, upon request, within 15 days of the applicant's receipt of a request.

(h) If an offset, overlying, or underlying operator, or a lessee or unleased mineral interest owner determines that any operator has assigned identical acreage to two or more concurrently producing wells in violation of this section, the operator or owner may file a complaint with the Hearings Division to request that a hearing be set to consider the issues raised in the complaint. If the Commission determines after a hearing on the complaint that acreage has been assigned in violation of this section, the Commission may curtail or cancel the allowable production rate for any affected wells and/or may cancel the Certificate of Compliance (Form P-4) for any affected wells for failure to comply with this section.

(i) An operator shall file Form P-16, Acreage Designation, with each drilling permit application and with each completion report for horizontal wells in any field and for all wells in designated UFT fields as defined in §3.86 of this title. An operator assigning surface acreage to more than one well pursuant to subsection (g) of this section shall file Form P-16, Acreage Designation, with each drilling permit application and with each completion report. The operator may file Form P-16 with each drilling permit application and with each completion report for all other wells. The operator may also file proration unit plats for individual wells in a field.

Source Note: The provisions of this §3.40 adopted to be effective January 1, 1976; amended to be effective January 9, 2002, 27 TexReg 150; amended to be effective February 1, 2016, 41 TexReg 785; amended to be effective March 3, 2020, 45 TexReg 1387.

§3.41 Application for New Oil or Gas Field Designation and/or Allowable

(a) The commission shall assign a new field designation and/or discovery allowable after an operator furnishes to the commission's Austin office proper evidence, other than horizontal distance, proving that a well is a new discovery. An operator shall include the following in the application:

(1) a legible area map, drawn to scale, preferably on white paper, which shows the following:

(A) all oil, gas, and abandoned wells within at least a 2 1/2-mile radius of the well claimed to be a discovery well;

(B) the producing intervals of all pertinent oil and gas wells identified in subparagraph (A) of this paragraph;

(C) all commission-recognized fields within a 2 1/2-mile radius of the well claimed to be a discovery well, that are presently active or were active in the past, identified by commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(D) the total depth of all wells identified in subparagraph (A) of this paragraph that penetrated the subject zone;

(E) scale, legend, and name of person who prepared the map;

(2) a complete legible electric log of the well. However, an operator is not required to file a complete electric log if the operator has filed all other required data, a portion of the log showing the top and bottom of the proposed reservoir interval, log headings, and applicable scales, and satisfactorily proves discovery as a new reservoir. Any electric log filed shall be considered public information pursuant to §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16).

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

(4) a subsurface structure map and/or cross section(s), if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the producing formation and the line(s) of cross section. The cross section(s) shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and hydrocarbon reservoir identified. The engineer or geologist who prepared the map and cross section shall sign them.

(5) reservoir pressure measurements or calculations, if separation is based on pressure differentials.

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

(b) The staff may require additional data deemed necessary to make a determination. Deviation from the requirements of subsection (a) of this section may be allowed at the staff's discretion.

(c) The director, oil and gas, may administratively grant an application if all required data is submitted with the form prescribed, and the evidence proves that the new reservoir is effectively separated from any other reservoir previously shown to be productive.

(d) If the director of the Oil and Gas Division, or the director's delegate, declines administratively to grant an application, the operator may request a hearing. If the commission receives the hearing request within 10 days of the date of the notice of administrative denial of the application, the commission shall schedule a hearing. After hearing, the examiner shall recommend final commission action.

Source Note: The provisions of this §3.41 adopted to effective January 1, 1976; amended to be effective July 24, 1980, 5 TexReg 2859; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective January 4, 1999, 24 TexReg 131.

§3.42 Oil Discovery Allowable

(a) The commission shall determine the discovery allowable rate for oil wells proven to be completed in a new and separate reservoir from the following discovery allowable schedule.

Scale of Allowables		
Interval of Depth	Daily Well Allowable	
	Onshore	Offshore
0 - 999	100 barrels	300 barrels
1,000 - 1,999	100 barrels	300 barrels
2,000 - 2,999	100 barrels	300 barrels
3,000 - 3,999	100 barrels	300 barrels
4,000 - 4,999	130 barrels	330 barrels
5,000 - 5,999	160 barrels	360 barrels
6,000 - 6,999	200 barrels	400 barrels
7,000 - 7,999	270 barrels	470 barrels
8,000 - 8,999	340 barrels	540 barrels
9,000 - 9,999	440 barrels	640 barrels
10,000 - 10,499	510 barrels	710 barrels
10,500 - 10,999	590 barrels	790 barrels
11,000 - 11,499	670 barrels	870 barrels
11,500 - 11,999	750 barrels	950 barrels
12,000 - 12,499	830 barrels	1,030 barrels
12,500 - 12,999	910 barrels	1,110 barrels
13,000 - 13,499	1,000 barrels	1,200 barrels
13,500 - 13,999	1,100 barrels	1,300 barrels
14,000 - 14,499	1,200 barrels	1,400 barrels
14,500 - 14,999	1,360 barrels	1,560 barrels
15,000 - 15,499	1,520 barrels	1,720 barrels
15,500 - 15,999	1,760 barrels	1,960 barrels

(b) Duration and exemption from market demand limitation.

(1) Onshore. Each oil well completed in an oil reservoir determined by the commission to be a new onshore oil field onshore may receive, as a maximum daily, its discovery allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the 11th oil well has been completed therein, whichever occurs first.

(2) Offshore. Each oil well completed in an oil reservoir determined by the commission to be a new offshore oil field may receive, as a maximum daily allowable, its discovery oil allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the sixth oil well has been completed therein, whichever occurs first.

(c) The director or the director's delegate shall review the production performance of discovery wells to evaluate whether waste is occurring due to the discovery allowable. If the director or the director's delegate believes waste is or may be occurring, the director or the director's delegate may request any additional relevant information from the operator and may set the matter for hearing to allow the commission to determine if the discovery allowable should be lowered to prevent waste.

Source Note: The provisions of this §3.42 adopted to be effective January 1, 1976; amended to be effective August 6, 1980, 5 TexReg 2930; amended to be effective November 28, 1989, 14 TexReg 6006; amended to be effective January 4, 1999, 24 TexReg 131.

§3.43 Application for Temporary Field Rules

(a) The commission will accept applications for temporary field rule hearings for oil, gas, or geothermal resource fields after the first well has been completed.

(b) When requesting such hearings, the applicant must furnish the commission a list of the names and addresses of all operators holding leases on land touching the tract on which the discovery well is located. The applicant must list the names and addresses of the owners of the abutting unleased land.

(c) Temporary field rules will apply until permanent field rules are adopted.

Source Note: The provisions of this §3.43 adopted to be effective January 1, 1976.

§3.45 Oil Allowables

(a) Oil allowable yardsticks.

(1) 1947 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred prior to January 1, 1965, provided that paragraph (3) of this subsection does not apply.

Depth	10 Ac.	20 Ac.	40 Ac.
0 - 1,000	18	28	
1,000 - 1,500	27	37	57
1,500 - 2,000	36	46	66
2,000 - 3,000	45	55	75
3,000 - 4,000	54	64	84
4,000 - 5,000	63	73	93
5,000 - 6,000	72	82	102
6,000 - 7,000	81	91	111
7,000 - 8,000	91	101	121
8,000 - 8,500	103	113	133
8,500 - 9,000	112	122	142
9,000 - 9,500	127	137	157
9,500 - 10,000	152	162	182
10,000 - 10,500	190	210	230
10,500 - 11,000		225	245
11,000 - 11,500		255	275
11,500 - 12,000		290	310
12,000 - 12,500		330	350
12,500 - 13,000		375	395
13,000 - 13,500		425	445
13,500 - 14,000		480	500
14,000 - 14,500		540	560

(2) 1965 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred on or after January 1, 1965.

Depth	10 Ac.	20 Ac.	40 Ac.	80 Ac.	160 Ac.
0 - 2,000	21	39	74	129	238
2,000 - 3,000	22	41	78	135	249
3,000 - 4,000	23	44	84	144	265
4,000 - 5,000	24	48	93	158	288
5,000 - 6,000	26	52	102	171	310
6,000 - 7,000	28	57	111	184	331
7,000 - 8,000	31	62	121	198	353

8,000 - 8,500	34	68	133	215	380
8,500 - 9,000	36	74	142	229	402
9,000 - 9,500	40	81	157	250	435
9,500 - 10,000	43	88	172	272	471
10,000 - 10,500	48	96	192	300	515
10,500 - 11,000		106	212	329	562
11,000 - 11,500		119	237	365	621
11,500 - 12,000		131	262	401	679
12,000 - 12,500		144	287	436	735
12,500 - 13,000		156	312	471	789
13,000 - 13,500		169	337	506	843
13,500 - 14,000		181	362	543	905
14,000 - 14,500		200	400	600	1,000

(3) Exception. Wells in fields discovered prior to January 1, 1965, whose discovery allowables either have expired or will expire subsequent to July 1, 1964, upon expiration of the discovery allowable, may be assigned allowable pursuant to the 1965 yardstick, if such allowables exceed those which would be assigned pursuant to the 1947 yardstick, or if the proration unit size authorized by the commission is not provided for in the 1947 yardstick. It is provided that any adjustment made in allowable assignment pursuant to this paragraph shall not be made prior to the effective date of this order. Retroactive adjustment shall not be allowed.

(4) Texas offshore allowable yardstick.

Depth	40 Ac.	80 Ac.	160 Ac.
0 - 2,000	200	330	590
2,000 - 3,000	220	360	640
3,000 - 4,000	245	400	705
4,000 - 5,000	275	445	785
5,000 - 6,000	305	490	865
6,000 - 7,000	340	545	950
7,000 - 8,000	380	605	1,050
8,000 - 9,000	420	665	1,150
9,000 - 10,000	465	730	1,260
10,000 - 11,000	515	800	1,380
11,000 - 12,000	565	875	1,500
12,000 - 13,000	620	950	1,625
13,000 - 14,000	675	1,030	1,750
14,000 - 15,000	735	1,115	1,880

(5) The maximum daily allowable for a horizontal drainhole oil well or an oil well in a designated unconventional fracture treated (UFT) field is set forth in §3.86(d)(4) and (5) of this title (relating to Horizontal Drainhole Wells).

(b) Assignment of allowables for wells under statewide rules.

(1) All wells completed in fields operating under statewide rules which were assigned the 20-acre yardstick allowable prior to the adoption of the new spacing rule on October 1, 1962, will be continued at the same allowable rate unless, after notice and hearing, special rules or other special orders are adopted that would provide for a higher producing rate. Any new well completed in such a reservoir will be given the same allowable rate as is assigned the other wells even though it has been drilled as a regular location under the new statewide spacing rule and density rule.

(2) All wells completed in fields operating under statewide rules that are presently on discovery status or have had discovery status terminated subsequent to the adoption of the new state spacing rule on October 1, 1962, will be given the 40-acre yardstick allowable, until such time as a change is ordered by the commission.

(c) Production of marginal wells.

(1) To artificially curtail the production of any "marginal well" below the marginal limit prior to its ultimate plugging and abandonment is hereby declared to be waste, and no rule or order of the Railroad Commission of Texas, or other constituted legal authority shall be entered requiring restriction of the production of any "marginal well" as defined in this chapter.

(2) Application of paragraph (1) of this subsection shall be confined to unrestricted operating conditions which accord with established operating rules of the commission, and shall be subject to all operating conditions designed to prevent waste imposed by the commission, which conditions apply to all wells alike. (Reference Order Number 20-54,115, effective January 1, 1965.)

Source Note: The provisions of this §3.45 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 1, 2016, 41 TexReg 785.

§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.

Source Note: The provisions of this §3.46 adopted to be effective January 1, 1976; amended to be effective April 1, 1982, 7 TexReg 655; amended to be effective January 1, 1994, 18 TexReg 8871; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective April 7, 1998, 23 TexReg 3432; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.47 Allowable Transfers for Saltwater Injection Wells

An allowable transfer will not be authorized for a well converted from oil production to saltwater disposal; however, an operator may make application to use the well for dual-purpose waterflood and saltwater disposal if injection is into an oil productive zone, and it is shown that the water injection will not injure the reservoir but will probably be of benefit to the reservoir as a secondary recovery program even though the beneficial effect of the water injection cannot be readily determined.

Source Note: The provisions of this §3.47 adopted to be effective January 1, 1976.

§3.48 Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

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

(1) Capacity oil allowable--The allowable assigned from time to time by the director of the Oil and Gas Division or the director's delegate to an oil lease or unit engaged in a secondary or tertiary recovery program, that is consistent with the ability of the lease or unit to produce and that will prevent the occurrence of overproduced status for the lease or unit. Capacity oil allowables encompass and supercede what the Railroad Commission formerly designated as waterflood allowables.

(2) Offsetting operators and unleased mineral interest owners affected by the application--All offsetting operators and unleased mineral interest owners to the lease or unit except for those offsetting operators and unleased mineral owners the director of the Oil and Gas Division or the director's delegate determines to be unaffected by the application.

(b) Application. The director of the Oil and Gas Division or the director's delegate may grant a capacity oil allowable for a lease or unit, to the operator of a secondary or tertiary recovery project, when evidence of production increase in response to the secondary or tertiary recovery project is noted. The operator's application for a capacity oil allowable shall consist of:

(1) a written request that shall contain a statement indicating that all offsetting operators and unleased mineral interest owners affected by the application have been sent a copy of the complete application, and a list of such offsetting operators and unleased mineral interest owners indicating the date that notification was sent;

(2) evidence of the operator's participation in the subject secondary or tertiary recovery project;

(3) a plat indicating all producing wells and injection wells on the lease or unit and all offsetting operators and unleased mineral interest owners to the lease or unit;

(4) if available, signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application; and

(5) a production graph illustrating both increased production and volumes of water or other substances used in the secondary or tertiary recovery project that have been injected on the lease or unit since initiation of the secondary or tertiary recovery project.

(c) Notice and hearing. If the operator does not submit signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, there shall be a minimum of 21 days notice of the application for a capacity oil allowable; provided that, if the operator requests a hearing to consider the application, such hearing shall be held only after at least 10 days notice. If the director of the Oil and Gas Division or the director's delegate declines to approve the initial application, or if a protest is received by the Oil and Gas Division within the prescribed notice period, the operator may request a hearing to show that the capacity oil allowable is necessary either to prevent waste or to protect correlative rights. Any hearing held pursuant to this section shall be held only after at least 10 days notice. If the operator submits signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, or if no protest is received by the Oil and Gas Division within the 21-day notice period, or if no protestant appears at a hearing to consider an application for a capacity oil allowable, the capacity oil allowable may be granted administratively by the director of the Oil and Gas Division or the director's delegate if the application establishes that the capacity oil allowable is necessary to ensure maximum recovery from the secondary or tertiary recovery project.

(d) Temporary basis. A capacity oil allowable may be granted on a temporary basis by the director of the Oil and Gas Division or the director's delegate upon receipt of a complete application indicating that an immediate allowable increase is necessary to ensure maximum recovery from the secondary or tertiary recovery project. If a hearing is held to consider the application, any capacity oil allowable previously granted on a temporary basis under this section will remain in effect until a signed order of the Railroad Commission is issued in the matter. If the commission order denies the application, or if an applicant fails to request a hearing to consider a protested application, additional production resulting from the

capacity oil allowable granted on a temporary basis will be treated as overproduction.

Source Note: The provisions of this §3.48 adopted to be effective March 28, 1988, 13 TexReg 1257.

§3.49 Gas-Oil Ratio

(a) Any oil well producing with a gas-oil ratio in excess of 2,000 cubic feet of gas per barrel of oil produced shall be allowed to produce daily only that volume of gas obtained by multiplying its maximum daily oil allowable, as determined by the allocation formula applicable to the well, by 2,000. The gas volume thus obtained shall be known as the daily gas limit of the well. The daily oil allowable of the well shall then be determined by dividing its daily gas limit, obtained as provided in this section, by its producing gas-oil ratio in cubic feet per barrel of oil produced.

(b) Any gas well producing from the same reservoir in which oil wells are completed and producing shall be allowed to produce daily only that amount of gas which is the volumetric equivalent in reservoir displacement of the gas and oil produced from the oil well in the reservoir that withdraws the maximum amount of gas in the production of its daily oil allowable.

(1) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of 100,000 or more.

$$Q = A\left(r_1 - r_2 + \frac{199.3\ PrB}{TrZ}\right)$$

Where:

Q = Gas well allowable, cubic feet per day at 14.65 PSIA and 60° F.

A = Top oil well allowable, barrels per day at 60° F.

r_1 = Permissible gas-oil ratio applicable to reservoir, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F.

r_2 = Cubic feet of gas dissolved in one (1) barrel of oil at average reservoir conditions, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F.

Pr = Average reservoir pressure at gas-oil contact, PSIA.

Tr = Average reservoir temperature at gas-oil contact, degrees Rankine.

B = Formation volume factor of reservoir oil at average reservoir conditions, dimensionless.

Z = Deviation factor of gas from ideal gas laws at average reservoir pressure and temperature, dimensionless.

(2) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of less than 100,000 under the provisions of the rule stated.

$$Q = \frac{A\left(r_1 - r_2 + \frac{199.3\ PrB}{TrZ}\right)}{1 - \frac{r_2}{r_3} + \frac{199.3\ PrB}{r_3\ TrZ}}$$

Where:

r_3 = Gas-oil ratio of gas well, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F. Other symbols are as above.

(3) The allowable for an associated gas well as determined by this subsection shall be limited to the lesser of:

(A) the gas well allowable as calculated by paragraph (1) or (2) of this subsection;

(B) the well's capability as determined by §3.31(e) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31); or

(C) the highest monthly production during those months averaged to a daily amount for wells that reported production during any of the three most recently reported production months.

(c) The necessary reservoir data shall be obtained from the file of the most recent MER hearing or shall be estimated by the commission unless more recent information is submitted by the operators.

(d) If the gas produced from an oil reservoir is returned to the same reservoir from which it was produced, only the volume of gas not returned to the reservoir shall be considered in applying the rule stated.

(e) Associated gas wells.

(1) Subsection (b) of this section will not be applicable to associated gas wells in reservoirs for which unlimited net gas-oil ratio authority has been granted for oil wells, where such net gas is defined as total gas produced less gas diverted to legal uses; however, this subsection does not apply to reservoirs where net gas is defined as total gas produced less gas returned to the reservoir from which it was produced, or where special field rules have been adopted for associated gas wells, or where a total gas volume limitation is placed upon the oil well producing under a net ratio, except that each associated gas well in such a reservoir shall be entitled to an additional gas voidage not to exceed the limitation placed upon the net ratio authority granted and the facts are shown on the current oil proration schedule for the field.

(2) Allowables for associated gas wells producing from reservoirs that are subject to an unlimited net gas-oil ratio authority will be dropped from the associated gas well schedule, effective that date such an unlimited net gas-oil ratio is authorized for any oil well in such reservoir.

(f) All gas-oil ratios determined by test or allocation shall be reported on the oil well status report form in accordance with instructions thereon and the provisions of §3.53(a) of this title (relating to Annual Well Tests and Well Status Reports Required).

(g) Allowables.

(1) No well shall have its allowable curtailed below the allowable fixed by the applicable field rules and the general statewide market demand order, unless such well is incapable of producing this allowable on a calendar day basis.

(2) Any well that has a gas-oil ratio in excess of the prescribed ratio for the field in which it is located will have its schedule daily allowable penalized due to such ratio.

Source Note: The provisions of this §3.49 adopted to be effective January 1, 1976; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.50 Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain Railroad Commission approval and certification of enhanced oil recovery (EOR) projects pursuant to Texas Tax Code, §202.052, §202.054, and §202.0545.

(b) Applicability.

(1) This section applies to:

(A) new EOR projects and the change from secondary EOR projects to tertiary projects which qualify as new EOR projects, and which begin active operation on or after September 1, 1989; and

(B) expansions of existing EOR projects.

(2) An EOR project may not qualify as an expansion if the project has qualified as a new EOR project under this section.

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

(1) Active operation--The start and continuation of a fluid injection program for a secondary or tertiary recovery project to enhance the displacement process in the reservoir. Applying for permits and moving equipment into the field alone are not considered active operations.

(2) Anthropogenic carbon dioxide--Carbon dioxide produced as a result of human activities.

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

(4) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(5) Comptroller--The Comptroller of Public Accounts.

(6) Enhanced oil recovery project (EOR)--The use of any process for the displacement of oil from the reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process. This term does not include pressure maintenance or water disposal projects.

(7) Existing enhanced recovery project--An EOR project that has begun active operation but was not approved by the Commission as a new EOR project.

(8) Expanded enhanced recovery project or expansion--The addition of injection and producing wells, the change of injection pattern, or other commission approved operating changes to an existing enhanced oil recovery project that will result in the recovery of oil that would not otherwise be recovered.

(9) Fluid injection--Injection through an injection well of a fluid (liquid or gaseous) into a producing formation as part of an EOR project.

(10) Incremental production--The volume of oil produced by an expanded enhanced recovery project in excess of the production decline rate established under conditions before expansion of an existing enhanced recovery project.

(11) Oil recovery from an enhanced recovery project--The oil produced from the designated area the commission certifies to be affected by the project.

(12) Operator--The person recognized by the commission as being responsible for the actual physical operation of an EOR project and the wells associated with the EOR project.

(13) Positive production response--Occurs when the rate of oil production from wells within the designated area affected by an EOR project is greater than the rate that would have occurred without the project.

(14) Pressure maintenance--The injection of fluid into the reservoir for the purpose of maintaining the reservoir pressure at or near the bubble point or other critical pressure wherein fluid injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(15) Primary recovery--The displacement of oil from the reservoir into the wellbore(s) by means of the natural pressure of the oil reservoir, including artificial lift.

(16) Production decline rate--The projected future oil production from a project area as extrapolated by a method approved by the commission.

(17) Recovered oil tax rate--The tax rate provided by the Tax Code, §202.052(b).

(18) Secondary recovery project--An enhanced recovery project that is not a tertiary recovery project.

(19) Termination--Occurs when the approved fluid injection program associated with an EOR project stops or is discontinued.

(20) Tertiary recovery project--An EOR project using a tertiary recovery method (as defined in the federal June 1979 energy regulations referred to in the Internal Revenue Code of 1986, §4993, or approved by the United States secretary of the treasury for purposes of administering the Internal Revenue Code of 1986, §4993, without regard to whether that section remains in effect) including those listed as follows:

(A) Alkaline (or caustic) flooding--An augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals.

(B) Carbon dioxide augmented waterflooding--Injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency.

(C) Cyclic steam injection--The alternating injection of steam and production of oil with condensed steam from the same well or wells.

(D) Immiscible carbon dioxide displacement--Injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained.

(E) In situ combustion--Combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells.

(F) Microemulsion, or micellar/emulsion, flooding--An augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, cosurfactant, an electrolyte and water, and polymers for mobility control.

(G) Miscible fluid displacement--An oil displacement process in which gas or alcohol is injected into an oil reservoir, at pressure levels such that the injected gas or alcohol and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected gas may be natural gas, enriched natural gas, a liquefied petroleum gas slug driven by natural gas, carbon dioxide, nitrogen, or flue gas. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

(H) Polymer augmented waterflooding--Augmented waterflooding in which organic polymers are injected with the water to improve a real and vertical sweep efficiency.

(I) Steam drive injection--The continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells).

(21) Water disposal project--The injection of produced water into the reservoir for the purpose of disposing of the produced water wherein the water injection volumes are not sufficient to refill existing reservoir voidage in the

approved project area and displace oil that would not be displaced by primary recovery operations.

(d) Application requirements. To qualify for the recovered oil tax rate the operator shall:

(1) submit an application for approval on the appropriate form. All applications must be filed at the Commission's Austin office. The form shall be executed and certified by a person having knowledge of the facts entered on the form. If an application is already on file under the Natural Resources Code, Chapter 101, Subchapter B, or for approval as a tertiary recovery project for purposes of the Internal Revenue Code of 1986, §4993, the operator may file a new EOR project and area designation application if the active operation of the project does not begin before the application under this section is approved by the Commission;

(2) submit all necessary forms to the Oil and Gas Division and provide the Commission with any relevant information required to administer this section such as: area plats showing the proposed project area and all injection and producing wells within the area, production and injection history, planned enhanced oil recovery procedures, and any other pertinent data;

(3) obtain a unitization agreement if required for purposes of carrying out the project under the Natural Resources Code, Chapter 101, Subchapter B. The Commission may not approve the project unless the unitization is approved; and

(4) submit an application on the appropriate form and obtain the necessary permits to conduct fluid injection operations pursuant to §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Statewide Rule 46), if such permits have not already been obtained.

(e) Concurrent applications. The operator may file concurrently:

(1) an application for approval of a new or expanded EOR project under this section, together with;

(2) an application for approval of a unitization agreement for purposes of carrying out the enhanced oil recovery project under the Natural Resources Code, §§101.001 et seq.; or

(3) an application for approval for certification of the project as a tertiary recovery project.

(f) Opportunity for hearing. A commission representative may administratively approve the application. If the commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the commission.

(g) Approval and certification.

(1) Project approval. In order to be eligible for the recovered oil tax rate as provided in the Tax Code, §202.052(b), the operator shall apply for and be granted Commission approval of a new EOR project or an expansion of an existing EOR project, prior to commencing active operation of the new project or expanded project. For a project to be approved the operator shall:

(A) prove that it qualifies as an EOR project;

(B) designate the area to be affected by the project and obtain Commission approval of the designation; and

(C) if production from the wells within the project area is reported with production from wells not in the project area, designate the method to account for and report production from the project area.

(2) Positive production response certificate.

(A) The operator of an EOR project that meets the requirements of this section shall demonstrate to the Commission a positive oil production response before the operator can receive Commission certification of such a positive production response. The certification date may be any date desired by the operator, subject to Commission approval, following the date on which a positive oil production response first occurred. The operator shall apply for a positive production response certificate within three years of project approval for secondary projects, and within five years of project approval for tertiary projects, to qualify for the recovered oil tax rate. The oil produced from the designated area of a new EOR project or incremental oil produced from the designated area of an expanded EOR project after the date of certification of a positive production response is eligible for the recovered oil tax rate. The operator shall apply to the comptroller pursuant to the Tax Code, §202.052 and §202.054, to qualify for the recovered oil tax rate.

(B) The application for positive response certification shall include:

(i) production and injection graphs with supporting tabular data illustrating a positive production response and volumes of water or other substances that have been injected on the designated area since the initiation of the new or the expanded EOR project;

(ii) a plat of the affected area showing all injection and producing wells, with completion dates; and

(iii) any other data requested by the Oil and Gas Division.

(C) The application for the positive production response certificate shall be processed administratively. If the Commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

(h) Annual reporting.

(1) The operator shall file an annual report on the appropriate form with the Oil and Gas Division each year the project remains eligible for the reduced severance tax rate. This form shall be filed within 30 days of the first anniversary of the date that the Commission acted on the EOR positive production response certification application and annually thereafter.

(2) The report shall contain the following:

(A) Commission certification date of positive production response;

(B) monthly volume of injected fluid(s) and anthropogenic carbon dioxide;

(C) number of well(s) used for injection;

(D) monthly production of oil, gas, and water;

(E) number of active producing wells; and

(F) any other relevant information requested by the Oil and Gas Division.

(i) Reduced or enlarged areas. The operator may apply for reduced or enlarged project area certification if the application for reduction or enlargement is received prior to the filing of an application for positive production response certification of the original enhanced oil recovery project.

(j) Termination and penalty. Upon approval by the Commission and the comptroller, the recovered oil tax rate shall continue for a maximum of 10 years, unless the project is sooner terminated. If the project is terminated prior to the 10-year period, the operator shall notify the Commission and the comptroller in writing within 30 days after the last day of active operations. Failure to so notify may result in civil penalties, interest, and the tax due. If the Commission determines a project has been terminated or there is action that affects the tax rate, it shall notify the comptroller immediately in writing.

(k) Additional tax rate reduction for enhanced recovery projects using anthropogenic carbon dioxide.

(1) Subject to the limitations provided by Texas Tax Code, §202.0545, until the later of the seventh anniversary of the date that the Comptroller of Public Accounts first approves an application for a tax rate reduction under this subsection or the effective date of a final rule adopted by the United States Environmental Protection Agency regulating carbon dioxide as a pollutant, the producer of oil recovered through an EOR project that qualifies under Texas Tax Code, §202.054, for the recovered oil tax rate provided by Texas Tax Code, §202.052(b), is entitled to an additional 50 percent reduction in that tax rate if in the recovery of the oil the EOR project uses carbon dioxide that:

(A) is captured from an anthropogenic source in this state;

(B) would otherwise be released into the atmosphere as industrial emissions;

(C) is measurable at the source of capture; and

(D) is sequestered in one or more geological formations in this state following the EOR process.

(2) In the event that a portion of the carbon dioxide used in the EOR project is anthropogenic carbon dioxide that satisfies the criteria of paragraph (1) of this subsection and a portion of the carbon dioxide used in the project fails to satisfy the criteria of paragraph (1) of this subsection because it is not anthropogenic, the tax reduction provided by paragraph (1) of this subsection shall be reduced to reflect the proportion of the carbon dioxide used in the project that satisfies the criteria of paragraph (1) of this subsection.

(3) To qualify for the tax rate reduction under this subsection, the operator shall:

(A) apply for a certification from the Commission if carbon dioxide used in the project is to be sequestered in an oil or natural gas reservoir; and

(B) apply to the Comptroller of Public Accounts for the reduction and include with the application any information and documentation that the comptroller may require.

(4) To qualify for the additional reduced recovered oil tax rate under this subsection the operator shall:

(A) submit an application for certification to the Commission's Austin Office for approval on the appropriate form that is executed and certified as provided for on the form; and

(B) provide the Commission with:

(i) plats showing the proposed project area and all wells within the area;

(ii) production and injection history;

(iii) planned enhanced oil recovery procedures;

(iv) information to demonstrate that the carbon dioxide to be injected is anthropogenic and a description of the method(s) of capturing and measuring the captured carbon dioxide at the source;

(v) a description of the planned sequestration program reasonably expected to ensure that at least 99% of the sequestered carbon dioxide will remain sequestered for at least 1,000 years;

(vi) planned monitoring and verification measures, including the planned duration of such measures, that will be employed to demonstrate that the sequestration program is performing as expected; and

(vii) any other pertinent information requested by the Commission.

(5) The Commission may issue the certification for the reduced tax rate under this subsection only if the Commission finds that, based on substantial evidence, there is a reasonable expectation that:

(A) the operator's planned sequestration program will ensure that at least 99 percent of the anthropogenic carbon dioxide sequestered will remain sequestered for at least 1,000 years; and

(B) the operator's planned sequestration program includes appropriately designed monitoring and verification measures that will be employed for a period sufficient to demonstrate whether the sequestration program is performing as expected.

(6) The operator is responsible for making application to the Comptroller of Public Accounts for the additional tax rate reduction.

(7) The additional tax rate reduction under this subsection does not apply and the operator will be required to repay the amount of tax that would have been imposed in the absence of this subsection if the operator's sequestration program or the operator's monitoring and verification measures differ substantially from the planned program approved by the Commission.

(8) In conjunction with the Annual Report required to be filed under subsection (h) of this section, an operator shall submit information concerning the operator's monitoring and verification measures results as proposed in the application for certification to demonstrate whether the sequestration program is performing as expected. In the event that the operator's sequestration program, including monitoring and verification measures, differs substantially from the program certified by the Commission under subsection (k) (5) of this section, the operator shall include with the Annual Report a written description of any material changes in the sequestration program.

(9) A Commission representative may administratively approve or deny an application for certification. If the Commission representative administratively denies an application, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

Source Note: The provisions of this §3.50 adopted to be effective February 20, 1990, 15 TexReg 652; amended to be effective March 18, 1992, 17 TexReg 1615; amended to be effective November 17, 1993, 18 TexReg 7922; amended to be effective April 6, 1998, 23 TexReg 3435; amended to be effective October 12, 2003, 28 TexReg 8585; amended to be effective January 7, 2008, 33 TexReg 114.

§3.51 Oil Potential Test Forms Required

(a) A completed potential test form shall be filed with the Commission not later than the deadline for filing completion reports under §3.16 of this title (relating to Log and Completion or Plugging Report). If the operator fails to file a potential test in an acceptable form prior to the deadline for filing completion reports as specified under §3.16 of this title, then the effective date of the allowable resulting from the test shall not extend back more than 30 days prior to the date that the test form, properly completed, is filed with the Commission. This 30-day provision shall govern regardless of whether the potential test is taken during the month in which it is received by the Commission or any prior month.

(b) The initial potential test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.51 adopted to be effective January 1, 1976; amended to be effective February 1, 2016, 41 TexReg.

§3.52 Oil Well Allowable Production

(a) The daily allowable production of any lease or property shall not include production based upon the daily potential production of the field or area in which such well is located unless such well is actually on production, and such lease or property shall share in the total allowable production of the field or area, only to the extent of such well's actual ability to produce from day to day regardless of the rated potential production thereof according to the commission schedules.

(b) Production of a well in any one day shall not exceed 110% of the top well allowable as fixed by applicable rules and orders. Production and runs from a lease during the monthly allowable period shall not exceed 105% of the monthly allowable for the well or wells on the lease. However, the volume of oil that is produced and removed from the producing property as tolerance production shall be treated as overproduction and overruns shall be made up during the next succeeding month.

(c) All oil allowable volumes shall be measured in a manner consistent with §3.71 of this title (relating to Pipeline Tariffs) (Statewide Rule 71).

(d) A newly completed well coming into production during a proration period will be gauged either by a commission agent, or pipeline gauger if a commission agent is not available, if an offset lease owner witnesses the gauge taken by the pipeline gauger. The allowable production of such newly completed well shall be in addition to the existing total allowable production of the field as previously ascertained. The well whose allowable is thus fixed shall take its ratable share of production at the next succeeding schedule date according to rule.

(e) All oil produced from any well governed by any proration order of the commission shall be charged against the allowable daily production of such well regardless of the disposition which is made of the oil so produced.

(f) The operator of any lease or unitized area in the State of Texas may be permitted to produce the total allowable for any such lease or unitized area subject to the following provisions:

(1) The operator must submit an application to produce that total allowable on a lease or unit production basis to the commission with a plat showing the subject lease or unit as well as the adjacent properties thereto. Such plat shall identify properly all properties and wells. The applicant shall give written notice to all operators in the field when application is made for permission to produce on a lease basis in a field. If no protest is received by the commission within 15 days of the date of mailing, the application may be granted by administrative action. If protest is received, notice will be given and the matter set for hearing.

(2) The total daily allowable of the lease or unit shall be initially established as an allowable equal to the sum of the current allowables for all wells on the lease or unit. The allowable credited to any new or existing well may be increased to the top well allowable permitted by subsequently filing a new potential test on that well. The maximum total daily allowable of the lease or unit will be equal to the sum of the scheduled top allowables assignable to each well for its proration unit.

(3) The total daily allowable of the lease or unit may be produced in any quantity from any well or combination of wells with the exception that wells nearer than a regular location from a lease or unit line shall not be permitted to produce more than their normal allowables and wells at a distance of a regular location from a lease or unit line shall not be produced at a rate of more that two times the top allowable for such well unless waivers of objection to rates in excess of this limit have been obtained from the operators of wells offsetting the well.

(4) Annual well test or allocation:

(A) An annual well test, or an allocation pursuant to §3.53(a)(2) of this title (relating to Annual Well Tests and Well Status Reports Required) shall be made and reported on the oil well status report form on each lease or unit property to which a lease production basis has been granted showing an individual well test or allocation on each oil well on the property made during the prescribed test period determined by the commission. Annual well tests may be witnessed by offset operators. An offset operator that desires to witness an annual well test shall give the testing operator written notice of its desire to witness the next scheduled annual well test of a specific well. A testing operator that has received prior written notice that an offset operator desires to witness an annual well test shall give that offset operator at least 24 hours advance notice of the date of the next annual well test for that well. The Commission will use the test or allocation data in the preparation of the oil proration schedule. The total schedule daily lease allowable shall be the sum of the individual well allowables as determined under applicable rules and the lease production basis shall be designated on the oil proration schedule by an appropriate symbol. All wells on the lease for which an allowable is requested shall have their production volumes reported pursuant to §3.53(a).

(B) Any producing well with a gas-oil ratio in excess of that permitted by the applicable rules shall have its daily allowable calculated by dividing the producing gas-oil ratio into the daily gas limit of the well.

(5) The Commission shall continue to require special tests in cases of commingled production where individual lease apportionment is determined by this method. Other special tests may be required as the Commission deems necessary.

(6) In the event that the monthly gas production of the lease or unit exceeds the permissible monthly lease gas limit, the volume of gas in excess of the lease gas limit shall be considered overproduction and must be made up by underproduction of the lease gas limit. Whenever the overproduced amount equals the next month's lease gas limit the overproduced amount shall immediately be reduced to zero by shutting in the lease or by other means acceptable to the Commission.

(7) The East Texas Field is excluded from the provisions of this section.

(g) Administrative cancelation of overproduction.

(1) An operator may request in writing to the Commission that overproduction for a specific lease be canceled. The request shall include a listing of the names and addresses of all offsetting operators in the same field as the lease for which the request is filed.

(2) Upon receipt of an operator's written request:

(A) Commission staff shall determine whether the operator's wells on the specified lease are in compliance with Commission rules excluding rules pertaining to overproduction.

(B) If the wells are found to be in compliance, the Commission staff shall send written notice to offset operators as identified in the request advising them of the request and giving them not less than 15 days to file a written objection to the request.

(C) If no objection to the request is received, the overproduction on the lease requested by the operator shall be canceled.

(D) If objection to the request is received or if Commission staff determines that the operator's wells are not in compliance with Commission rules excluding rules pertaining to overproduction, then the requested cancelation shall not be administratively approved. The

operator may request that the matter be scheduled for public hearing pursuant to Tex. Nat. Res. Code §86.090. The burden of proof shall be on the applicant operator.

Source Note: The provisions of this §3.52 adopted to be effective January 1, 1976; amended to be effective May 1, 1991, 16 TexReg 2095; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective February 1, 2016, 41 TexReg 785.

§3.53 Annual Well Tests and Well Status Reports Required

(a) Oil wells.

(1) Unless otherwise provided for in this section, each operator of producing oil wells shall annually test each producing oil well for a 24-hour period during the test period specified on the well status report form and shall record all oil, gas and water volumes resulting from the test on the form.

(2) For any oil well capable of producing no more than five barrels of oil per 24-hour period, the operator of such well may report the required oil, gas and water volumes based on an allocation of that well's production on a prorated daily basis, rather than an actual well test. This option of using production allocation instead of actual well tests does not apply to surface-commingled wells, swabbed wells, the East Texas Field or the following Panhandle fields: Panhandle Carson County Field (Field Number 68845-001); Panhandle Collingsworth County Field (Field Number 68859-001); Panhandle Gray County Field (Field Number 68873-001); Panhandle Hutchison County Field (Field Number 68887-001); Panhandle Moore County field (Field Number 68901-001); Panhandle Potter County Field (Field Number 68915-001); and Panhandle Wheeler County Field (Field Number 68929-001).

(3) Each operator of a well or wells listed in the oil proration schedule shall file with the commission an oil well status report form in accordance with instructions on the form. All wells on a lease, and injection and disposal wells, must be reported.

(4) Changes in oil well status filed between regularly scheduled oil well status surveys shall be submitted on oil well status report forms in accordance with instructions thereon.

(b) Gas wells. Each operator of a gas well producing liquid hydrocarbons shall file with the commission gas well status reports in accordance with instructions thereon.

Source Note: The provisions of this §3.53 adopted to be effective January 1, 1976; amended to be effective November 21, 1980, 5 TexReg 4419; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79.

As in effect on 12/9/2024.

§3.54 Gas Reports Required

(a) Gas processing plant report. As soon after the first day of each calendar month as practicable, and never later than the 25th day of each calendar month, the operator of each plant manufacturing or extracting liquid hydrocarbons, including gasoline, butane, propane, condensate, kerosene, or other derivatives from natural gas, or refinery or storage vapors, shall file, in duplicate, in the Austin office, a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(b) Pressure maintenance and repressuring plant report.

(1) As soon after the first day of each month as practicable, but never later than the 15th day of each calendar month, the operator of each plant that returns natural gas to oil or gas producing reservoirs, or both, for the purpose of maintaining pressure or repressuring an oil or gas reservoir, but is not reporting such gas on any other commission approved form, shall file in duplicate in the district office a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(2) Pressure maintenance.

(A) The operator of each pressure-maintenance or repressuring plant shall file the report although no liquid hydrocarbons are recovered.

(B) The term "pressure-maintenance plant" or "repressuring plant" as used herein means any equipment or device, mechanical or otherwise, used for the purpose of returning any natural gas, residue gas from a gas processing plant, including plant and storage vapors, to an underground oil reservoir if the plant is operated as a separate unit. If pressure maintenance or repressuring operations are conducted as an integral part of a gas processing plant extracting, manufacturing, or recovering liquid hydrocarbons from natural gas or vapors, or both, the operations shall be reported by the operator of the processing plant.

(c) Producer's report of condensate and/or crude oil produced from gas wells. As soon as practicable after the first day, and never later than the last day of the calendar month, subsequent to the period of the report, the operator of each gas well from which liquids are recovered on the lease shall file the required form.

(d) Carbon black plant report. As soon as practicable after the first day and never later than the 15th day of each calendar month, each operator of a carbon black plant shall file a report. The report shall cover the operation of the plant for the immediately preceding month and shall be filed in duplicate in the district office.

(e) Monthly gas production report. As soon after the first day of each month as practicable, and never later than the last day of the calendar month, subsequent to the period of

the report, every operator producing natural gas from wells classified as either gas wells or oil wells by the commission, except those expressly exempted by the commission shall file a report on the required form.

Source Note: The provisions of this §3.54 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 7, 1991, 16 TexReg 2297.

§3.55 Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering

(a) When the full well stream from a gas well is moved to a plant or central separation facilities, and the liquid hydrocarbons produced by two or more wells are commingled without being measured or metered from each gas well, the operator of each well so producing shall periodically file with the commission, as provided for in this section, a report showing the following information for each well:

(1) the specific gravity of the gas at 60 degrees Fahrenheit, after the removal of the liquid hydrocarbons;

(2) the API gravity corrected to 60 degrees Fahrenheit of the liquid hydrocarbons removed;

(3) the number of stock tank barrels of liquid hydrocarbons (corrected to 60 degrees Fahrenheit) recovered per 1,000 standard cubic feet of gas.

(b) Tests.

(1) The tests necessary for this report shall be made by one or more of the following methods:

(A) conventional mechanical separation;

(B) low temperature separation;

(C) split stream method;

(D) in accordance with AGA-NGAA Testing Code 101-43.

(2) The tests shall be made semiannually, or quarterly if contracts for royalty payments require quarterly tests. Semiannual tests must be made during the first and third or second and fourth quarters of the year. If a contract for royalty payments requires quarterly tests, the tests shall be made during each quarter. Both semiannual and quarterly tests may be made during any month of the quarter if the same (first, second, or third) month of each quarter is used thereafter for any well.

(c) The results of each test shall be submitted in duplicate on the appropriate commission form to the proper commission district office not later than the 15th day of each month following the month in which the test is made. The tests shall be required when the conditions set out in the first paragraph of this section exist, regardless of whether or not the conditions are an exception to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil) (Statewide Rule 26). The tests shall not be required, however, in any reservoir in which 100% of the operating and royalty ownership has been unitized.

(d) This section does not purport to alter any procedure for periodic tests of gas wells that has previously been approved by the commission. If test periods agreed upon by the interested parties have not been approved by the commission, and if the periods agreed upon differ from the test periods provided for in this section, alternative testing periods may be approved by the commission upon application.

Source Note: The provisions of this §3.55 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.56 Scrubber Oil and Skim Hydrocarbons

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

(1) Identifiable liquid hydrocarbons--Volume of scrubber oil/skim hydrocarbons that is received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons can be clearly identified.

(2) Producing property--A location from which hydrocarbons are being produced that has been assigned a lease identification number by the Commission and which is used in reporting production.

(3) Scrubber oil--Liquid hydrocarbons which accumulate in lines that are transporting casinghead gas and which are captured at the inlet to a gas processing plant.

(4) Skim hydrocarbons--Oil and condensate which accumulate during produced water disposal operations.

(5) Tolerance--The amount of skim hydrocarbons that may be recovered before the produced water disposal system operator must allocate to the producing property.

(6) Unidentifiable liquid hydrocarbons--Scrubber oil/skim hydrocarbons received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons cannot be identified.

(b) Disposition of scrubber oil, skim hydrocarbons, and identifiable liquid hydrocarbon volumes.

(1) Scrubber oil. Any scrubber oil that has not been returned to a producing property by the end of a monthly report period shall be reported by the operator of the gas plant on the monthly plant report, Form R-3 (Monthly Report for Gas Processing Plants). The unidentifiable

liquid hydrocarbons recovered and reported on Form R-3 may be disposed of at the point of accumulation. The accepted Form R-3 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(2) Skim hydrocarbons.

(A) All unidentifiable liquid hydrocarbons recovered by a single operator or multiple operator produced water disposal system shall be reported on the Form P-18 (Skim Oil/Condensate Report) for each reporting period.

(B) The unidentifiable liquid hydrocarbons recovered and reported on Form P-18 may be disposed of at the point of accumulation. The accepted Form P-18 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(C) Unidentifiable liquid hydrocarbons recovered by a single operator produced water disposal system shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period.

(D) Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period. The produced water disposal system operator shall notify the operator of each producing property of any allocations to that property by furnishing a copy of the allocations as shown on Form P-18 (Skim Oil/Condensate Report).

(E) The operator of each producing property shall report the volume of liquid hydrocarbons allocated to the producing property as production from the property on Form PR, Monthly Production Report. The volume allocated back shall be shown as skim oil or skim condensate on the form.

(3) Identifiable liquid hydrocarbon volumes.

(A) Identifiable liquid hydrocarbon volumes returned to the producing property during the reporting period in which the volume is received at the gas plant/produced water disposal facility shall not be reported to the Commission by the gas plant/facility operator. The gas plant/produced water disposal facility operator shall notify the appropriate Commission district office by telephone prior to the return of such volumes. The movement of these volumes back to the producing property shall comply with §3.85 of this title (relating to Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle), commonly referred to as Statewide Rule 85.

(B) Identifiable volumes not returned to the producing property shall be reported to the Commission and to the operator of the producing property on Form R-3 or Form P-18 as prescribed in paragraph (1) or (2) of this subsection. Volumes shall be specifically credited to the appropriate producing property. The operator of the producing property shall report the disposition of such identifiable volumes as either skim hydrocarbons or scrubber oil on the appropriate production report.

Source Note: The provisions of this §3.56 adopted to be effective January 10, 2000, 25 TexReg 80; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 287.

§3.57 Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials

(a) Applicability. This section is applicable to reclamation of tank bottoms and other hydrocarbon wastes generated through activities associated with the exploration, development, and production (including transportation) of crude oil and other waste materials containing oil, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The provisions of this section shall not apply where tank bottoms or other hydrocarbon-bearing materials are recycled or processed on-site by the owner/custodian and are returned to a tank or vessel at the same lease or facility. This section is not applicable to the practice of recycling or reusing drilling mud, except as to those hydrocarbons recovered from such mud recycling and sent to a permitted reclamation plant.

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

(1) Tank bottoms--A mixture of crude oil or lease condensate, water, and other substances that is concentrated at the bottom of producing lease tanks and pipeline storage tanks (commonly referred to as basic sediment and water or BS&W).

(2) Other hydrocarbon wastes--Oily waste materials, other than tank bottoms, which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The term "other hydrocarbon wastes" includes, but is not limited to, pit hydrocarbons, skim oil, spillage, and leakage of crude oil or condensate from producing lease or pipeline storage tanks, and crude oil or condensate associated with pipeline ruptures and other spills.

(3) Authorized person--A tank bottoms cleaner or transporter that is under contract for disposition of untreated tank bottoms or other hydrocarbon wastes to a person who has obtained a permit to operate a reclamation plant.

(4) Affected person--A person who has suffered or will suffer actual injury or economic damage other than as a member of the general public and includes surface owners of property on which a reclamation plant is located and surface owners of adjoining properties.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(c) Permitting process.

(1) Removal of tank bottoms or other hydrocarbon wastes from any producing lease tank, pipeline storage tank, or other production facility, for reclaiming by any person, is prohibited unless such person has either obtained a permit to operate a reclamation plant, or is an authorized person. Applicants for a reclamation plant operating permit shall file the appropriate form with the commission in Austin.

(2) The applicant shall give notice by mailing or delivering a copy of the application to the county clerk of the county where the reclamation plant is to be located, and to the city clerk or other appropriate city official of any city where the reclamation plant is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission.

(3) In order to give notice to other local governments and 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 reclamation plant is to be located, in a form approved by the commission. Publication shall occur on or before the date the application is mailed to or filed with the commission. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(4) 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, or if the commission 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.

(5) If no protest from an affected person or local government is received by the commission within the allotted time, the director may administratively approve the application. If the director 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) Applicants must demonstrate they are familiar with commission rules and have the proper facilities to comply with the rules.

(7) Except as provided in subparagraphs (A) and (B) of this paragraph, a permit to operate a reclamation plant shall remain in effect until canceled at the request of the operator. Existing permits subject to annual renewal may be renewed so as to remain in effect until canceled. Such renewal shall be subject to the requirements of paragraph (10) of this subsection. A reclamation plant permit may be canceled by the commission after notice and opportunity for hearing, if:

(A) the permitted facility has been inactive for 12 months; or

(B) there has been a violation, or a violation is threatened, of any provision of the permit, the conservation laws of the state, or rules or orders of the commission.

(8) If the operator objects to the cancellation, the operator must file, within 15 days of the date shown on the notice, a written objection and request for a hearing to determine whether the permit should be canceled. If such written request is timely filed, the cancellation will be suspended until a final order is issued pursuant to the hearing. If such request is not received within the required time period, the permit will be canceled. In the event of an emergency which presents an imminent pollution, waste, or public safety threat, the commission may suspend the permit until an order is issued pursuant to the hearing.

(9) A permit to operate a reclamation plant is not transferable. A new permit must be obtained by the new operator.

(10) Reclamation plants permitted under this section shall file financial security as required under §3.78(l) of this title (relating to Fees and Financial Security Requirements).

(d) Operation of a reclamation plant.

(1) The following provisions apply to any removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility.

(A) Notwithstanding the provisions of §3.85(a)(8) of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), an operator of a reclamation plant or an authorized person shall execute a manifest in accordance with §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), upon each removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility. In addition to the information required pursuant to §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), the operator of the reclamation plant or other authorized person shall also include on the manifest:

(i) the commission identification number of the lease or facility from which the material is removed; and

(ii) the gross and net volume of the material as determined by the required shakeout test.

(B) The operator of the reclamation plant or other authorized person shall fill out the manifest before leaving the lease or facility from which the liquid hydrocarbons

are removed, and shall retain a copy on file for two years.

(C) The operator of the reclamation plant or other authorized person shall leave a copy of the manifest in the vehicle transporting the material.

(2) The operator of a reclamation plant or other authorized person shall conduct a shakeout (centrifuge) test on all tank bottoms or other hydrocarbon wastes upon removal from any producing lease tank, pipeline storage tank, or other production facility, to determine the crude oil content and lease condensate thereof.

(3) The shakeout test shall be conducted in accordance with the most current American Petroleum Institute or American Society for Testing Materials method.

(e) Reporting of reclaimed crude oil or lease condensate on commission required report.

(1) For wastes taken to a reclamation plant the following provisions shall apply.

(A) The net crude oil content or lease condensate from a producing lease's tank bottom as indicated by the shakeout test shall be used to calculate the amount of oil to be reported as a disposition on the monthly production report. The net amount of crude oil or lease condensate from tank bottoms taken from a pipeline facility shall be reported as a delivery on the monthly transporter report.

(B) For other hydrocarbon wastes, the net crude oil content or lease condensate of the wastes removed from a tank, treater, firewall, pit, or other container at an active facility, including a pipeline facility, shall also be reported as a disposition or delivery from the facility.

(2) The net crude oil content or lease condensate of any tank bottoms or other hydrocarbon wastes removed from an active facility, including a pipeline facility, and disposed of on-site or delivered to a site other than a reclamation plant shall also be reported as a delivery or disposition from the facility. All such disposal shall be in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). Operators may be required to obtain a minor permit for such disposal using procedures set out in §3.8(d) and (g) of this title (relating to Water Protection). Prior to approval of the minor permit, the commission may require an analysis of the disposable material to be performed.

(f) General provisions applicable to materials taken to a reclamation plant.

(1) The removal of tank bottoms or other hydrocarbon wastes from any facility for which monthly reports are not filed with the commission must be authorized in writing by the commission prior to such removal. A written request for such authorization must be sent to the commission office in Austin, and must detail the location, description, estimated volume, and specific origin of the material to be removed, as well as the name of the reclaimer and intended destination of the material. If the authorization is denied, the applicant may request a hearing.

(2) The receipt of any tank bottoms or other hydrocarbon wastes from outside the State of Texas must be authorized in writing by the commission prior to such receipt. However, written approval is not required if another entity will indicate, in the appropriate monthly report, a corresponding delivery of the same material. If the request is denied, the applicant may request a hearing.

(3) The receipt of any waste materials other than tank bottoms or other hydrocarbon wastes must be authorized in writing by the commission prior to such receipt. The commission may require the reclamation plant operator to submit an analysis of such waste materials prior to a determination of whether to authorize such receipt. If the request is denied, the applicant may request a hearing.

(4) The operator of a reclamation plant shall file a report on the appropriate commission form for each reclamation plant facility by the 15th day of each calendar month, covering the facility's activities for the previous month. The operator of a reclamation plant shall file a copy of the monthly report in the district office of any district in which the operator made receipts or deliveries for the month covered by the report.

(5) All wastes generated by reclaiming operations shall be disposed of in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(g) Commission review of administrative actions. Administrative actions performed by the director or commission staff pursuant to this rule are subject to review by the commissioners.

(h) Policy. The provisions of this rule shall be administered so as to prevent waste and protect correlative rights.

Source Note: The provisions of this §3.57 adopted to be effective April 11, 1990, 15 TexReg 1693; amended to be effective June 1, 1998, 23 TexReg 5656; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271.

§3.58 Certificate of Compliance and Transportation Authority; Operator Reports

(a) Certificate of Compliance and transportation authority.

(1) Each operator who seeks to operate any well subject to the jurisdiction of the Commission shall file with the commission's Austin office a commission form P-4 (certificate of compliance and transportation authority) for each property on which the wells are located certifying that the operator has complied with Texas Natural

Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, and orders, rules, and regulations of the commission pursuant to Texas Natural Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, in respect to the property. The Commission form P-4 establishes the operator of an oil lease, gas well, or other well; certifies responsibility for regulatory compliance, including plugging wells in accordance with §3.14 of this title (relating to plugging); and identifies gatherers, purchasers, and purchasers' commission-assigned system codes authorized for each well or lease. Operators shall file form P-4 for new oil leases, gas wells, or other wells; recompletions; reclassifications of wells from oil to gas or gas to oil; consolidation, unitization or subdivision of oil leases; or change of gatherer, gas purchaser, gas purchaser system code, operator, field name or lease name. When an operator files a form P-4, the oil and gas division shall review the form for completeness and accuracy. The Commission may require an operator who files a form P-4 for the purpose of changing the designation of an operator for a lease or well to provide to the Commission evidence that the transferee has the right to operate the lease or well. Except as otherwise authorized by the Commission, a transporter (whether the operator or someone else) shall not transport the oil, gas, or geothermal resources from such property until the Commission has approved the certificate of compliance and transportation authority. No certificate of compliance designating or changing the designation of an operator will be approved that is signed, either as transferor or transferee, by a non-employee agent of the organization unless the organization has filed with the commission, on its organization report, the name of the non-employee agent it has authorized to sign such certificates of compliance on its behalf.

(2) An approved certificate of compliance and transportation authority shall bind the operator until another operator files a subsequent certificate and the Commission has approved the subsequent certificate and transferred the property on commission records to the subsequent operator.

(3) The appropriate district office or the Austin office may grant temporary authority for an operator to use a transporter not authorized for a particular property in order to take care of production and prevent waste. The operator shall secure such temporary authority in writing from the appropriate district office or the Austin office before the oil or condensate is moved. In an emergency situation the operator may secure such temporary authority verbally but shall notify the district office in writing within 10 days after the oil or condensate is moved. An emergency situation exists when oil or condensate must be moved off a lease because it poses an imminent threat to the public health and safety, or when the threat of waste is imminent. The operator shall also furnish copies of such authorization or notification to the regular transporter and to the temporary transporter.

(4) If an applicant wishes to assume operator status for a property, but is unable to obtain the signature of the previous operator on the certificate of compliance and transportation authority, the applicant shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent of the applicant, along with an explanatory letter and legal documentation of the applicant's right to operate the property. Prior to approval of such an application, the office of the general counsel will notify the last known operator of record, if such operator's address is available, affording such operator an opportunity to protest.

(b) Monthly production report (oil, natural gas and geothermal resources). For each calendar month, each operator who is a producer of crude oil, natural gas or geothermal resources shall file with the commission a report for each of the operator's producing properties. Operators shall file such reports on commission Form PR, Monthly Production Report, or commission Form GT-2 (producer's monthly report of geothermal wells). These commission forms report monthly production and disposition of oil and condensate, and casinghead gas and gas well gas (Form PR) and geothermal resources (Form GT-2). On or before the last day of the month subsequent to the period of the report, the operator shall file the original form with the Austin office, and one copy with the transporter taking the oil, gas or geothermal resources from the property if requested by the transporter.

(c) Recovered load oil.

(1) The operator of each lease from which load oil is recovered shall file the original and one copy of commission form P-3 (authority to transport recovered load or frac oil) with the district office, and another copy with the transporter prior to running the load oil. Form P-3 requires a producer to report the quantity of recovered load or frac oil to be transported from a particular lease and to identify the transporter. The form P-3 (authority to transport recovered load or frac oil) filed by the operator shall be the authority for the transporter to run the quantity of recovered load or frac oil stated in the form.

(2) The provisions of this subsection apply only to oil that has been obtained from a source other than the lease on which it is used. "Recovered load oil or frac oil," as that term is used herein, is any oil or liquid hydrocarbons used in any operation in an oil or gas well, and which has been recovered as a merchantable product.

(d) Subdivision and consolidation of oil leases.

(1) An operator seeking to subdivide or consolidate existing oil leases shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). Form P-6 identifies the leases to be subdivided or consolidated as well as the resulting leases. Two plats shall be filed with form P-6, one showing the boundaries of the lease(s) before and one showing the boundaries of the lease(s) after the subdivision or consolidation.

(2) An operator seeking to subdivide an existing oil lease that it operates or to assume operatorship of fewer than all of the wells on an oil lease shall file and obtain

approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to subdivide an oil lease may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules.

(3) An operator seeking to consolidate two or more existing oil leases that it operates shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to consolidate two or more oil leases may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules and:

(A) the mineral and royalty ownership of the leases proposed for consolidation is identical in all respects;

(B) the operator has obtained a surface commingling exception permit pursuant to §3.26 of this title (relating to separating devices, tanks, and surface commingling of oil) that authorizes commingling of production from all of the leases proposed for consolidation; or

(C) the operator has filed and obtained approval of a valid commission form P-12 (certificate of pooling authority) authorizing pooling of all of the leases proposed for consolidation.

Source Note: The provisions of this §3.58 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective May 12, 2002, 27 TexReg 3756; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective November 26, 2007, 32 TexReg 8452.

§3.59 Oil and Gas Transporter's Reports

(a) General. The commission may, from time to time, require oil and gas pipeline companies to make reports to the commission showing wells connected with their lines during any month, the amount of production taken therefrom, names of parties from whom oil and gas are purchased, and the amount of oil or gas purchased therefrom.

(b) Daily report. The commission may, in case of overproduction or for any other reason which it deems urgent, require oil and gas pipe line companies to furnish daily reports of the amount of oil or gas purchased or taken from different wells or parties.

(c) Weekly stock report. Rescinded by Order Number 20-57,970, effective 11-16-67.

(d) Monthly transportation and storage report.

(1) Each gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall file with the commission on or before the last day of each calendar month a report showing the required information concerning the transportation operations of such gatherer, transporter, or storer for the next preceding month. Such form is incorporated in and made a part of this section.

(2) The original of the report, covering all of the operations of the gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall be filed in the Austin office of the commission. One copy of the report shall be filed in each district office in which the gatherer, transporter, storer, and/or handler of crude oil or products, or both, operates, but may include only the information pertaining to the operations in that district in which it is filed.

(3) The written instructions appearing on said form are incorporated in and made a part of this section, and all of the data and information on the form shall be reported and arranged on the form as required by the form.

(4) No gatherer, transporter, storer, and/or handler of crude oil shall remove crude oil from any property unless such property is identified by a sign posted in compliance with §3.3(3) of this title (relating to Identification of Properties, Wells, and Tanks).

(5) The provisions of this section shall not apply to the operator of any refinery, processing plant, blending plant, or treating plant to which §3.60 of this title (relating to Refinery Reports) applies if the operator has filed the required form.

(e) Annual report.

(1) Each common carrier pipeline shall make and file with the commission, at its Austin office, an annual report for each calendar year. The report must show the names of the officers, directors, and stockholders, and the residence of each; the amount of capital stock and bonded indebtedness outstanding; the results of financial operations; the sources of revenue; and the expenditures, assets and liabilities, and statistical data of oil transported; and such other information as may be deemed pertinent by the commission concerning the carrier's transactions in the performance of services under its charter provisions relative to the transportation of crude petroleum in the State of Texas.

(2) The annual report must be made to the commission on the form prescribed and furnished by the commission; and must be returned complete, under oath, within 30 days after the receipt of the forms from the commission.

(3) For all purposes applicable under these rules and regulations the "Classification of Investment for Pipe Lines, Pipe Line Operating Revenues, and Pipe Line Operating Expenses" prescribed by the Interstate Commerce Commission and effective on January 1, 1915, is adopted and made a part of these rules for the use of all common carrier pipelines subject to the provisions of that

act of the legislature, being Chapter 30 of the Regular Session of the 35th Legislature, State of Texas.

Source Note: The provisions of this §3.59 adopted to be effective January 1, 1976.

§3.60 Refinery Reports

On or before the 15th day of each calendar month, the operator of each refinery, processing plant, blending plant or treating plant, and/or other plant situated within the state that processes or manufactures a product, except those gas processing plants for which another form is required by §3.54(a) of this title (relating to Gas Reports Required), shall file with the commission a report covering the operations of the refinery or plant during the preceding month. The report must contain the data and information required to be reported on the form.

Source Note: The provisions of this §3.60 adopted to be effective January 1, 1976.

§3.61 Refinery and Gasoline Plants

(a) The operator of each refinery in the state shall use tanks for measuring the crude oil and products taken into the refinery and the finished products of the refinery.

(b) No refinery or gasoline plant shall be operated without a certificate of compliance on a form supplied by the commission and approved by it, which shall be in effect for a period of 12 months, but may be renewed for one or more additional 12-month period. The operator must equip the plant with tanks and proper metering facilities.

(c) Measuring facilities for the accurate measurement of the volume of each type of gas taken into a natural gasoline plant shall be installed and used by the operator of the gasoline plant. Meters must be provided and used for measuring separately the dry sweet natural gas, the dry sour natural gas, casinghead gas, and refinery vapors taken into each plant. Accurate meters must be installed and used in each gasoline plant in which is processed dry gas (as distinguished from casinghead gas) so that all disposals of residue gas from such natural gasoline plant are accurately accounted for. Adequate devices should likewise be installed and used in each gasoline plant at which casinghead gas exclusively, or casinghead gas and refinery vapors only are processed, for the purpose of making approximate estimates of the volume of residue gas produced from such plant; such devices may consist either of meters, pilot tubes, pressure recording gauges, or manometers, through which measurements may be made from which reasonably accurate estimates of volume can be made.

(d) Measuring natural gasoline.

(1) Adequate tanks or meters of standard or approved types must be provided for measuring accurately all finished products of natural gasoline plants.

(2) The operator of each natural gasoline plant shall meter separately the volume of dry sweet natural gas, dry sour natural gas, casinghead gas, and refinery vapors that are taken into each natural gasoline plant.

(3) The operator of each natural gasoline plant in which dry natural gas (as distinguished from casinghead gas) is processed shall use metering facilities so that all disposition of residue gas from such natural gasoline plants are accurately accounted for. The operator of each natural gasoline plant in which casinghead gas exclusively, or casinghead gas and refinery vapors only, are processed shall install and use measuring devices, consisting either of meters, pitot tubes, pressure recording gauges, or manometers, with which measurements may be made of the residue gas disposition from the plant.

(4) The operator of each natural gasoline plant shall provide and use tanks or meters of standard or approved type for measuring each finished product of the plant.

Source Note: The provisions of this §3.61 adopted to be effective January 1, 1976.

§3.62 Cycling Plant Control and Reports

(a) The operator of each cycling plant shall use tanks for measuring the crude oil, condensate, or other liquid hydrocarbons taken into or extracted by the cycling plant.

(b) The operator of each cycling plant shall meter the following separately:

(1) all gas taken into the plant from statutory gas wells;

(2) all casinghead gas taken into the cycling plant;

(3) all gas used for plant fuel;

(4) all gas taken by pipe lines or for domestic or commercial uses;

(5) all gas, including flash vapors, vented directly or indirectly to the air.

(c) Gas used for lifting water by jetting, or used in turbines and subsequently vented to the air or burned in a flare, shall be accurately metered and reported by the operator as vented on the appropriate form.

(d) No cycling plant shall be permitted to vent any gas taken into the plant from statutory gas wells; however, the venting of a volume of flash vapors not to exceed 2.0% of the volume of gas taken into said plant shall be considered to be compliance.

(e) No gas shall be used for plant operation that is not burned in boilers, heaters, or internal combustion engines in a reasonably efficient manner, and no raw gas or residue gas shall be used for plant fuel if any flash vapors are being vented or flared.

(f) No cycling plant shall be operated without a certificate of compliance. The appropriate form submitted to the commission and approved by it shall be in effect for a period of 12 months, but may be renewed for one or more periods of 12 months. The certificate of compliance shall be revoked if an inspection reveals noncompliance.

Source Note: The provisions of this §3.62 adopted to be effective January 1, 1976.

§3.63 Carbon Black Plant Permits Required

(a) Each operator of a carbon black plant shall make application for a permit to operate the plant, using the appropriate form.

(b) No person shall operate a plant for the burning of natural gas in the manufacture of carbon black without a permit authorizing the operation of the plant.

(c) Each 12 months the commission, on application, may grant a permit to each of the operators of carbon black plants for a period of 12 months.

Source Note: The provisions of this §3.63 adopted to be effective January 1, 1976.

§3.65 Critical Designation of Natural Gas Infrastructure

(a) Definitions.

(1) In this section, the term "energy emergency" means any event that results in firm load shed or has the potential to result in firm load shed required by the reliability coordinator of a power region in Texas. An event that has the "potential to result in firm load shed" is when the reliability coordinator of a power region in Texas has issued an Energy Emergency Alert Level 1 or 2.

(2) In this section, the term "critical customer information" means the information required on Commission Form CI-D and any attachments.

(3) In this section, "any volume of gas indicated in Mcf/day" means the average daily production from the well's six most recently filed monthly production reports. Wells without six months of production reports shall average the production from the well's production reports on file with the Commission or use the production volume from the well's initial potential test or deliverability test if the well has not yet filed a production report.

(4) In this section, the term "electricity supply chain map" means the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee.

(5) In this section, the term "Director" means the Director of the Critical Infrastructure Division or the director's delegate.

(6) In this section, the term "EOR project" means an enhanced oil recovery project as defined in §3.50(c)(6) of this title (relating to Enhanced Oil Recovery Projects-Approval and Certification for Tax Incentive) with at least one injection well permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) whether or not the project has received Commission approval or certification under §3.50 of this title.

(b) Critical designation criteria. The following facilities are designated critical during an energy emergency:

(1) Critical Gas Supplier. The following facilities are designated a critical gas supplier:

(A) gas wells producing gas in excess of 250 Mcf/day;

(B) oil leases producing casinghead gas in excess of 500 Mcf/day, except for EOR projects provided the EOR project consumes more energy than it produces calculated by comparing the amount of electricity used to the amount of gas produced both in Million British Thermal Units (MMBTU);

(C) gas processing plants;

(D) natural gas pipelines and pipeline facilities including associated compressor stations and control centers;

(E) local distribution company pipelines and pipeline facilities including associated compressor stations and control centers;

(F) underground natural gas storage facilities;

(G) natural gas liquids transportation and storage facilities; and

(H) saltwater disposal facilities including saltwater disposal pipelines.

(2) Critical Customer. A critical customer is a critical gas supplier that requires electricity delivered by an electric entity to operate. A critical customer is required to provide critical customer information pursuant to subsection (f) of this section to the electric entities described in §25.52(h) of this title (relating to Reliability and Continuity of Service) and Texas Utilities Code §38.074(b)(1) so that those electric entities may prioritize the facilities in accordance with Texas Utilities Code §38.074(b)(2) and (b)(3). Priority for load shed purposes during an energy emergency is described by §25.52(h)(2) of this title and any guidance issued thereunder by the Public Utility Commission.

(c) Request for critical designation if not designated critical in subsection (b) of this section. A facility that is not designated critical under subsection (b) of this section may write to the Commission to apply to be designated critical if the facility's operation is required in order for

another facility designated critical to operate. The applicant shall include objective evidence that the facility's operation is required for another facility designated critical in subsection (b) of this section to operate. The director will review the application and if the application is approved, the facility shall submit Form CI-D. If the request is denied, the applicant may request a hearing.

(d) Acknowledgment of critical status. Except as provided by subsection (e) of this section, an operator of a facility designated as critical under subsection (b) or (c) of this section shall acknowledge the facility's critical status by filing Form CI-D as provided in this subsection. In the year 2022, the Form CI-D acknowledgment shall be filed bi-annually by January 15, 2022, and either September 1, 2022, or 30 days from the date the map is produced by the Texas Electricity Supply Chain Security and Mapping Committee, whichever is later. Beginning in 2023, the Form CI-D acknowledgment shall be filed bi-annually by March 1 and September 1 of each year.

(e) Critical designation exception.

(1) A facility listed in subsection (b) of this section that is not included on the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee may apply for an exception. An applicant shall demonstrate with objective evidence a reasonable basis and justification in support of the application. The Director of the Critical Infrastructure Division will administratively approve or deny a request for an exception. If the request is denied, the Division will notify the applicant and the applicant may request a hearing to challenge the denial. The party requesting the hearing shall have the burden of proof.

(2) Examples of a reasonable basis and justification for which an exception may be granted include, but are not limited to, the following:

(A) All of the natural gas produced at the facility is consumed on site;

(B) All of the natural gas produced, processed, or delivered by the facility is consumed outside of this state;

(C) The facility does not provide gas for third-party use;

(D) For saltwater disposal facilities and saltwater disposal pipelines, the facility or pipeline does not support a facility designated critical in subsection (b)(1)(A)-(G) of this section; or

(E) The electric entity delivering electricity to the facility has provided notice that the facility's request for critical designation status was rejected, denied, or otherwise disapproved by the electric utility; provided, however, that the electric utility communicated its determination in writing, and the decision was for reasons other than the lack of correct identifying information or other administrative reasons.

(3) An applicant for exception shall submit a Form CI-X exception application that identifies each facility for which an exception is requested. The Form CI-X shall be accompanied by an exception application fee. The amount of the fee is $150 as established in Chapter 81, Texas Natural Resources Code.

(A) In the year 2022, the Form CI-X exception application shall be filed bi-annually by January 15, 2022, and either September 1, 2022, or 30 days from the date the map is produced by the Texas Electricity Supply Chain Security and Mapping Committee, whichever is later. Beginning in 2023, the Form CI-X exception application shall be filed bi-annually by March 1 and September 1 of each year.

(B) Once an operator has an approved Form CI-X on file with the Commission, the operator is not required to pay the $150 exception application fee when the operator updates the facilities identified on its Form CI-X.

(f) Providing critical customer information. A critical customer shall provide the critical customer information to the electric entities described in §25.52 of this title and Texas Utilities Code §38.074(b)(1) unless the critical customer is granted an exception under subsection (e) of this section. The critical customer information shall be provided in accordance with §25.52 of this title. The operator shall certify on its Form CI-D that it has provided the critical customer information to its electric entity.

(g) Confidentiality of information filed pursuant to this section. A person filing information with the Commission that the person contends is confidential by law shall notify the Commission on the applicable form. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for materials that have been designated confidential, the Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the materials.

(h) Exceptions not transferable. Exceptions are not transferable upon a change of operatorship. When a facility is transferred, both the transferor operator and the transferee operator shall ensure the transfer is reflected on each operator's Form CI-D or Form CI-X when the applicable form update is submitted in accordance with the bi-annual filing timelines in subsections (d) and (e) of this section. If the facility has an exception under subsection (e) of this section, the exception shall remain in effect until the next bi-annual filing deadline. If the transferee operator seeks to continue the exception beyond that time period, the transferee operator shall indicate the transferred facility on the Form CI-X pursuant to subsection (e) of this section.

(i) Failure to file or provide required information. An operator who fails to comply with this section may be subject to penalties under §3.107 of this title (relating to Penalty Guidelines for Oil and Gas Violations).

Source Note: The provisions of this §3.65 adopted to be effective December 20, 2021, 46 TexReg 8688; amended to be effective November 21, 2022, 47 TexReg 7661.

§3.66. Weather Emergency Preparedness Standards

(a) Applicability.

(1) In accordance with Texas Natural Resources Code §86.044, this section applies to a gas supply chain facility that is:

(A) included on the electricity supply chain map created under Texas Utilities Code §38.203; and

(B) designated as critical in §3.65 of this title, relating to Critical Designation of Natural Gas Infrastructure.

(2) In accordance with Texas Utilities Code §121.2015, this section applies to a gas pipeline facility that:

(A) directly serves a natural gas electric generation facility operating solely to provide power to the electric grid for the Electric Reliability Council of Texas (ERCOT) power region or for the ERCOT power region and an adjacent power region; and

(B) is included on the electricity supply chain map created under Texas Utilities Code §38.203.

(b) Definitions. In this section, the following definitions apply.

(1) Critical component--Any component, including components on equipment rented or leased from a third party, that is susceptible to weather-related interruptions, such as those caused by freezing temperatures, freezing precipitation, or extreme heat, the occurrence of which is likely to significantly hinder sustained operation of the gas pipeline or gas supply chain facility.

(2) Gas pipeline facility--A pipeline or pipeline facility regulated by the Commission under Texas Utilities Code Chapter 121.

(3) Gas supply chain facility--A facility that is:

(A) used for producing, treating, processing, pressurizing, storing, or transporting natural gas, as well as handling waste produced;

(B) not primarily used to support liquefied natural gas pretreatment, liquefaction, or regasification facilities in the business of exporting or importing liquefied natural gas to or from foreign countries;

(C) otherwise regulated by the Commission under Subtitle B of Title 3, Texas Natural Resources Code; and

(D) not regulated by the Commission under Texas Utilities Code Chapter 121.

(4) Major weather-related forced stoppage--A weather-related forced stoppage during a weather emergency that is the result of the deliberate disregard of this section or that results in:

(A) a loss of production exceeding 5,000 Mcf of natural gas per day per oil lease;

(B) a loss of production exceeding 5,000 Mcf of natural gas per day per gas well;

(C) a loss of gas processing capacity exceeding 200 MMcf per day;

(D) a loss of storage withdrawal capacity exceeding 200 MMcf per day; or

(E) a loss of transportation capacity exceeding 200 MMcf per day.

(5) Repeated weather-related forced stoppage--When a gas supply chain facility or a gas pipeline facility has more than one major weather-related forced stoppage or weather-related forced stoppage violation within a 12-month period.

(6) Sustained operation--Safe operation of a gas supply chain facility or a gas pipeline facility such that the facility does not experience a major weather-related forced stoppage or weather-related forced stoppage in production, treating, processing, storage, or transportation of natural gas.

(7) Weather emergency--Weather conditions such as freezing temperatures, freezing precipitation, or extreme heat in the facility's county or counties that result in an energy emergency as defined by §3.65 of this title. A weather emergency does not include weather conditions that cannot be reasonably mitigated such as tornadoes, floods, or hurricanes.

(8) Weatherization--The iterative cycle of preparedness for sustained operation during weather emergencies that includes:

(A) correcting critical component failures that occurred during previous weather emergencies;

(B) installing equipment to mitigate weather-related operational risks; and

(C) internal inspection, self-assessment, and implementation of processes to identify, test, and protect critical components.

(9) Weather-related forced stoppage--An unanticipated and/or unplanned outage in the production, treating, processing, storage, or transportation of natural gas that is caused by weather conditions such as freezing temperatures, freezing precipitation, or extreme heat and occurs during a weather emergency.

(c) Weather emergency preparedness standards for a gas supply chain facility or a gas pipeline facility.

(1) By December 1st of each year, a gas supply chain

facility operator or a gas pipeline facility operator shall implement weather emergency preparation measures intended to:

(A) ensure the sustained operation of a gas supply chain facility or a gas pipeline facility during a weather emergency; and

(B) correct known major weather-related forced stoppages and weather-related forced stoppages that prevented sustained operation of a facility because of previous weather emergencies.

(2) Weather emergency preparation measures required by paragraph (1) of this subsection shall include:

(A) providing training on weather emergency preparations and operations to relevant operational personnel;

(B) consideration of the risk to the health and safety of employees and protection of the environment; and

(C) weatherization of the facility using methods a reasonably prudent operator would take given the type of facility, the age of the facility, the facility's critical components, the facility's location, and weather data for the facility's county or counties such as data developed for the Commission by the state climatologist. The Commission will periodically publish weatherization practices and may include weather data developed for the Commission by the state climatologist.

(d) Weather Emergency Readiness Attestation. By December 1 of each year, an operator of a gas supply chain facility or a gas pipeline facility shall submit to the Commission a Weather Emergency Readiness Attestation that:

(1) is signed by an authorized representative of the operator entity attesting, under penalties prescribed in Texas Natural Resources Code §91.143, that:

(A) the operator implemented the required weather emergency preparation measures described in subsection (c) of this section;

(B) the information and statements made in the Weather Emergency Readiness Attestation are true, correct, and complete to the best of the attestor's knowledge;

(C) the representative is authorized to sign the attestation on behalf of the operator entity; and

(D) the Weather Emergency Readiness Attestation was prepared by the authorized representative or under the authorized representative's supervision and direction;

(2) includes an attachment describing all activities engaged in by the operator to implement the requirements of subsection (c) of this section, including a description of the weatherization methods utilized by the operator to weatherize each type of facility; and

(3) for the Weather Emergency Readiness Attestation due December 1, 2022, also describes corrective actions taken to mitigate known major weather-related forced stoppages and weather-related forced stoppages that prevented sustained operation of a facility because of previous weather emergencies.

(e) Inspection of gas supply chain facilities and gas pipeline facilities. Beginning December 1, 2022, the Commission will inspect facilities to ensure compliance with this section and will prioritize inspections of oil leases and gas wells producing greater than 5,000 Mcf per day of natural gas and facilities storing, processing, or transporting greater than 200 MMcf per day of natural gas. The Commission will further prioritize inspections in descending order in accordance with a facility's production volume or storage, processing, or transportation capacity.

(f) Notifications and other requirements for gas supply chain facilities and gas pipeline facilities.

(1) An operator of a gas supply chain facility or a gas pipeline facility that experiences either of the following during a weather emergency shall notify the Commission immediately through the Critical Infrastructure Division's notification portal if the stoppage is not resolved within 24 hours of discovery of the stoppage:

(A) a weather-related forced stoppage; or

(B) a forced stoppage caused by a loss of electricity.

(2) An operator of a gas supply chain facility or gas pipeline facility that experiences either of the following during a weather emergency shall, within one hour of discovery of the stoppage, contact the Commission through the Critical Infrastructure Division's 24-hour emergency telephone number. Subsequent to the phone call, the operator shall submit a notification through the Critical Infrastructure Division's notification portal:

(A) a major weather-related forced stoppage; or

(B) a forced stoppage caused by a loss of electricity that results in the same volume of loss in natural gas production, withdrawal capacity, processing capacity, or transportation capacity as a major weather-related forced stoppage.

(3) The notification of the major weather-related forced stoppage or weather-related forced stoppage may include information such as any third-party issues that may have directly contributed to the stoppage, if applicable.

(4) A gas supply chain facility or a gas pipeline facility that is determined to have experienced repeated weather-related forced stoppages or major weather-related forced stoppages in sustained operation during a weather emergency shall comply with this paragraph. Upon notice from the Commission that the facility is required to comply with this paragraph, the facility's operator shall contract with a person with related experience to assess the facility's weather emergency preparation measures, plans, procedures, and operations. The person with related experience shall not be an employee of the facility or its

affiliate and shall not have participated in any assessments of the facility for at least the previous five years, unless the facility's operator can document that no other persons with related experience are reasonably available for engagement. Within the timeframe provided by the Commission, the operator shall submit to the Commission a written assessment prepared by the person and the facility operator's corrective action plan in compliance with the terms in the Commission's notice that the facility is required to comply with this paragraph.

(g) Enforcement.

(1) Violation of this section by a gas supply chain facility operator. If a major weather-related forced stoppage or weather-related forced stoppage was caused by a gas supply chain facility's failure to adhere to the requirements of this section, the facility's operator will be subject to an enforcement action. A gas supply chain facility operator will be given notice and opportunity for a hearing for alleged violations of this section. The notice will be sent by certified mail and state the facts or conduct alleged to comprise the violation. The notice will give the operator 30 days from receipt to request a hearing. Pursuant to Texas Natural Resources Code §86.044 and §§86.222-.224, if after notice and opportunity for a hearing, the Commission determines that an operator has violated this section and the violation is not remedied in a reasonable amount of time, the Commission shall notify the Office of the Attorney General of Texas of the violation in accordance with Texas Natural Resources Code §86.222. The table in this paragraph contains a classification system to be used under Texas Natural Resources Code §86.222 for violations of this section. The penalty for each violation may be up to $1,000,000.
Figure: 16 TAC §3.66(g)(1) ***[See Figure at the end of this document.]***

(2) Violation of this section by a gas pipeline facility operator.

(A) If a major weather-related forced stoppage or weather-related forced stoppage was caused by a gas pipeline facility's failure to adhere to the requirements of this section, the facility's operator will be subject to an enforcement action. A gas pipeline facility operator will be given notice and opportunity for a hearing for alleged violations of this section. The notice will be sent by certified mail and state the facts or conduct alleged to comprise the violation. The notice will give the operator 30 days from receipt to request a hearing. Pursuant to Texas Utilities Code §121.2015, if after notice and opportunity for a hearing, the Commission determines that an operator has violated this section and the violation is not remedied in a reasonable amount of time, the Commission shall report the violation to the Office of the Attorney General of Texas. Pursuant to Texas Utilities Code §121.206, the Commission shall assess an administrative penalty for a violation of this section, which may be up to $1,000,000 for each offense. Each day a violation continues constitutes a separate offense.

(B) In accordance with Texas Utilities Code §121.206(d), the Commission will use the table in paragraph (1) of this subsection in assessing penalties for a violation of this section. The penalty amounts contained in the table in paragraph (1) of this subsection are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of Texas Utilities Code, Chapter 121, Subchapter E, or a safety standard or other rule prescribed or adopted under that subchapter. The establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The Commission retains full authority and discretion to cite violations of Texas Utilities Code, Chapter 121, Subchapter E, or a safety standard or other rule prescribed or adopted under that subchapter, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section. The penalty calculation worksheet shown in the table in paragraph (1) of this subsection lists the typical penalty amounts for certain violators, the circumstances justifying enhancements of a penalty, and the circumstances justifying a reduction in a penalty.

(h) Confidentiality. If a gas supply chain facility operator or a gas pipeline facility operator filing information required by this section contends certain information is confidential by law, the operator shall file a complete version of the required information and a version for public inspection in which the confidential information has been redacted. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for materials that have been designated confidential, the Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the materials.

Source Note: The provisions of this §3.66 adopted to be effective September 19, 2022, 47 TexReg 5781

§3.70 Pipeline Permits Required

(a) Each operator of a pipeline or gathering system, other than an operator excluded under §8.1(b)(4) of this title (relating to General Applicability and Standards), subject to the jurisdiction of the Commission, shall obtain a pipeline permit, to be renewed annually, from the Commission as provided in this rule. Production or flow lines that are subject to §8.1(a)(1)(B) and (D) of this title must comply with this section. All other production or flow lines as defined in this subsection are exempt from complying with this section. A production or flow line is piping used for production operations that generally occur upstream of gathering or other pipeline facilities. For the purposes of this subsection, piping used in "production operations" means piping used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids, and includes the following processes:

(1) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement; and

(2) associated production compression, gas lift, gas injection, or fuel gas supply.

(b) To obtain a new pipeline permit or to amend a permit because of a change of classification, an operator shall file an application for a pipeline permit on the Commission's online permitting system. The operator shall include or attach the following documentation and information:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation or maintenance;

(2) the requested classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line;

(3) a sworn statement from the pipeline applicant providing the operator's factual basis supporting the classification and purpose being sought for the pipeline, including, if applicable, an attestation to the applicant's knowledge of the eminent domain provisions in Texas Property Code, Chapter 21, and the Texas Landowner's Bill of Rights as published by the Office of the Attorney General of Texas;

(4) documentation to provide support for the classification and purpose being sought for the pipeline, if applicable; and

(5) any other information requested by the Commission.

(c) To renew an existing permit, to amend an existing permit for any reason other than a change in classification, or to cancel an existing permit, an operator shall file an application for a pipeline permit on the Commission's online filing system. The operator shall include or attach:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation, or maintenance; change in operator or ownership; or other change including operator cessation of pipeline operation;

(2) a statement from the pipeline operator confirming the current classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line, if applicable; and

(3) any other information requested by the Commission.

(d) Upon receipt of a complete permit application, the Commission has 30 calendar days to issue, amend, or deny the pipeline permit as filed. If the Commission determines that the application is incomplete, the Commission shall promptly notify the applicant of the deficiencies and specify the additional information necessary to complete the application. Upon receipt of a revised application, the Commission has 30 calendar days to determine if the application is complete and issue, amend, or deny the pipeline permit as filed.

(e) If the Commission is satisfied from the application and the documentation and information provided in support thereof, and its own review, that the proposed line is or will be laid, equipped, managed and operated in accordance with the laws of the state and the rules and regulations of the Commission, the permit may be granted. The pipeline permit, if granted, shall classify the pipeline as a common carrier, a gas utility, or a private pipeline based upon the information and documentation submitted by the applicant and the Commission's review of the application.

(f) This rule applies to applications made for new pipeline permits and to amendments, renewals, and cancellations of existing pipeline permits. The classification of a pipeline under this rule applies to extensions, replacements, and relocations of that pipeline.

(g) The Commission may delegate the authority to administratively issue pipeline permits.

(h) The pipeline permit, if granted, shall be revocable at any time after a hearing, held after 10 days' notice, if the Commission finds that the pipeline is not being operated in accordance with the laws of the state and the rules and regulations of the Commission including if the permit is not renewed annually as required in subsection (a) of this section.

(i) Each pipeline operator shall pay an annual fee based on the pipeline operator's permitted mileage of pipeline not later than April 1 of each year.

(1) For purposes of calculating the mileage fee, the Commission will categorize pipelines into two groups.

(A) Group A includes transmission and gathering pipelines that are required by Commission rules to have a valid T-4 permit to operate and are subject to the regulations in 49 CFR Parts 192 and 195, such as natural gas transmission and storage pipelines, natural gas gathering pipelines defined as Type A, Type B, or Type C in 49 CFR §192.8, hazardous liquids transmission and storage pipelines, regulated rural hazardous liquids gathering pipelines under 49 CFR §195.11, and hazardous liquid low-stress rural pipelines under 49 CFR §195.12.

(B) Group B includes pipelines that are required by Commission rules to have a valid T-4 permit to operate but are only subject to the reporting requirements in 49 CFR Parts 191 and 195 such as Type R gathering pipelines as defined in 49 CFR §192.8, and reporting-regulated-only gathering lines as defined in 49 CFR §195.15.

(2) An operator of a Group A pipeline shall pay an annual fee of $20 per mile of pipeline based on the number of miles permitted to that operator as of December 31 of each year.

(3) An operator of a Group B pipeline shall pay an annual fee of $10 per mile of pipeline based on the number of miles permitted to that operator as of December 31 of each year.

(4) Any pipeline distance that is a fraction of a mile will be considered as one mile and will be assessed a $20 or $10 fee, as appropriate.

(5) Fees due to the Commission for mileage transferred from one operator to another operator pursuant to subsection (o) of this section will be captured in the next mileage fee to be calculated on the following December 31 and paid by the new operator.

(j) Each pipeline operator shall pay a $500 permit processing fee for each new permit application and permit renewal. Each operator shall file the annual renewals as follows:

(1) Companies with names beginning with letters A through C shall file in February;

(2) Companies with names beginning with letters D through E shall file in March;

(3) Companies with names beginning with letters F through L shall file in April;

(4) Companies with names beginning with letters M through P shall file in May;

(5) Companies with names beginning with letters Q through T shall file in June; and

(6) Companies with names beginning with letters U through Z and companies with names beginning with numerical values or other symbols shall file in July.

(k) Each operator shall comply with the following:

(1) If a permit is transferred, in the Commission fiscal year of the transfer the acquiring operator shall renew that permit in its designated month pursuant to subsection (j) of this section. If the acquiring operator receives a transferred permit in a Commission fiscal year and its renewal month has already passed, the acquiring operator shall pay the renewal fee upon transfer.

(2) If an operator adds a new permit and pays the new permit fee, the operator is not required to pay the renewal fee for that permit in the same Commission fiscal year.

(3) If an operator adds a new permit after its renewal month has passed, the new permit shall be renewed the following Commission fiscal year in the operator's designated month pursuant to subsection (j) of this section.

(l) A pipeline operator who fails to renew a permit on or before the renewal deadline which is the last day of the operator's required filing month as specified in subsection (j) of this section shall pay a late-filing fee as follows:

(1) $250, if the renewal application is received within 30 calendar days after the renewal deadline date;

(2) $500, if the renewal application is received more than 30 calendar days and no more than 60 calendar days after the renewal deadline date; and

(3) $700, if the renewal application is received more than 60 calendar days after the renewal deadline date.

(4) If the renewal application is not received within 90 calendar days of the renewal deadline date, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(m) A pipeline operator with a total mileage of 50 miles or less of pipeline who fails to pay the annual mileage fee as specified in subsection (i) of this section shall pay a late-filing fee as follows:

(1) $125, if the fee is received within 30 calendar days of April 1;

(2) $250, if the fee is received more than 30 calendar days and no more than 60 calendar days after April 1; and

(3) $350, if the fee is received more than 60 calendar days after April 1.

(4) If the fee is not received within 90 calendar days of April 1, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(n) A pipeline operator with a total mileage of more than 50 miles of pipeline who fails to pay the annual mileage fee shall pay a late-filing fee as follows:

(1) $250, if the fee is received within 30 calendar days of August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year;

(2) $500, if the fee is received more than 30 calendar days and no more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year; and

(3) $700, if the fee is received more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year.

(4) If the fee is not received within 90 calendar days of August 31 for the initial year that the requirement is in effect or April 1 for each subsequent year, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(o) A pipeline operator who has been issued a permit and is transferring the pipeline or a portion of the pipeline included on the permit to another operator shall file a notification of transfer with the Commission within 30 days following the transfer. The transferee and transferor operators shall file a fully executed Form T-4B as a

notification of transfer. The Commission may use a fully executed Form T-4B to remove the pipeline that is the subject of the transfer from the transferor operator and assign the mileage to the transferee operator for calculation of the annual mileage fee. The transferee operator shall amend its permit to include the pipeline or portion of the pipeline within 30 days following the Commission's approval of the transfer or the operator may be subject to a penalty for operating without a permit pursuant to subsection (p) of this section.

(1) A transferee operator may file a Form T-4B signed only by the transferee operator as a notification of transfer with the Commission only upon presenting to the Commission for its review, concurrently with Form T-4B:

(A) evidence that the transferee operator made a good faith effort to procure the transferor operator's signature; and

(B) documentation establishing that the transferee operator has a legal right to operate the pipeline.

(2) Prior to approving a single-signature Form T-4B filed pursuant to paragraph (1) of this subsection, the Commission shall issue notice to the transferor operator, providing the operator 15 days to contest the transfer and request a hearing. Upon receipt of a timely response requesting a hearing, the matter shall be referred to the Hearings Division for adjudication as a contested case.

(p) A pipeline operator who operates a pipeline without a permit, with an expired permit, or who otherwise fails to comply with this section, may be assessed a penalty as prescribed in §8.135 of this title (relating to Penalty Guidelines for Pipeline Safety Violations).

(q) Interstate pipelines are exempt from the fee requirements of this section.

(r) Beginning December 9, 2024, operators shall comply with the following.

(1) All gas permits shall be amended to include all gas gathering pipelines defined as Type A, Type B, Type C, or Type R in 49 CFR §192.8. The permit amendments shall be filed on the Commission's online permitting system by March 31, 2025. The amendment shapefile shall indicate each segment as Type A, Type B, Type C, or Type R, and include any other information requested by the Commission.

(2) A gas permit will not be eligible for renewal if the permit has not been amended by March 31, 2025, in accordance with paragraph (1) of this subsection. If the gas permit does not have any gas gathering pipelines to be amended or added, the operator shall include with its 2025 renewal submission a statement on the submitted cover letter attesting to that fact. The Commission may request additional information as necessary to confirm the statement.

Source Note: The provisions of this §3.70 adopted to be ***As in effect on 12/9/2024.***

effective August 25, 2003, 28 TexReg 6816; amended to be effective March 1, 2015, 39 TexReg 9969; amended to be effective June 25, 2018, 43 TexReg 4169; amended to be effective January 6, 2020, 45 TexReg 119; amended to be effective December 9, 2024, 49 TexReg 9958

§3.71 Pipeline Tariffs

Every person owning, operating, or managing any pipeline, or any part of any pipeline, for the gathering, receiving, loading, transporting, storing, or delivering of crude petroleum as a common carrier shall be subject to and governed by the following provisions. Common carriers specified in this section shall be referred to as "pipelines," and the owners or shippers of crude petroleum by pipelines shall be referred to as "shippers."

(1) All marketable oil to be received for transportation. By the term "marketable oil" is meant any crude petroleum adapted for refining or fuel purposes, properly settled and containing not more than 2.0% of basic sediment, water, or other impurities above a point six inches below the pipeline connection with the tank. Pipelines shall receive for transportation all such "marketable oil" tendered; but no pipeline shall be required to receive for shipment from any one person an amount exceeding 3,000 barrels of petroleum in any one day; and, if the oil tendered for transportation differs materially in character from that usually produced in the field and being transported therefrom by the pipeline, then it shall be transported under such terms as the shipper and the owner of the pipeline may agree or the commission may require.

(2) Basic sediment, how determined--temperature. In determining the amount of sediment, water, or other impurities, a pipeline is authorized to make a test of the oil offered for transportation from an average sample from each such tank, by the use of centrifugal machine, or by the use of any other appliance agreed upon by the pipeline and the shipper. The same method of ascertaining the amount of the sediment, water, or other impurities shall be used in the delivery as in the receipt of oil. A pipeline shall not be required to receive for transportation, nor shall consignee be required to accept as a delivery, any oil of a higher temperature than 90 degrees Fahrenheit, except that during the summer oil shall be received at any atmospheric temperature, and may be delivered at like temperature. Consignee shall have the same right to test the oil upon delivery at destination that the pipeline has to test before receiving from the shipper.

(3) "Barrel" defined. For the purpose of these sections, a "barrel" of crude petroleum is declared to be 42 gallons of 231 cubic inches per gallon at 60 degrees Fahrenheit.

(4) Oil involved in litigation, etc.--indemnity against loss. When any oil offered for transportation is involved in litigation, or the ownership is in dispute, or when the oil appears to be encumbered by lien or charge of any kind, the pipeline may require of shippers an indemnity bond to protect it against all loss.

(5) Storage. Each pipeline shall provide, without

additional charge, sufficient storage, such as is incident and necessary to the transportation of oil, including storage at destination or so near thereto as to be available for prompt delivery to destination point, for five days from the date of order of delivery at destination.

(6) Identity of oil, maintenance of oil. A pipeline may deliver to consignee either the identical oil received for transportation, subject to such consequences of mixing with other oil as are incident to the usual pipeline transportation, or it may make delivery from its common stock at destination; provided, if this last be done, the delivery shall be of substantially like kind and market value.

(7) Minimum quantity to be received. A pipeline shall not be required to receive less than one tank car-load of oil when oil is offered for loading into tank cars at destination of the pipeline. When oil is offered for transportation for other than tank car delivery, a pipeline shall not be required to receive less than 500 barrels.

(8) Gathering charges. Tariffs to be filed by a pipeline shall specify separately the charges for gathering of the oil, for transportation, and for delivery.

(9) Measuring, testing, and deductions (reference Special Order Number 20-63,098 effective June 18, 1973).

(A) Except as provided in subparagraph (B) of this paragraph, all crude oil tendered to a pipeline shall be gauged and tested by a representative of the pipeline prior to its receipt by the pipeline. The shipper may be present or represented at the gauging or testing. Quantities shall be computed from correctly compiled tank tables showing 100% of the full capacity of the tanks.

(B) As an alternative to the method of measurement provided in subparagraph (A) of this paragraph, crude oil and condensate may be measured and tested, before transfer of custody to the initial transporter, by:

(i) lease automatic custody transfer (LACT) equipment, provided such equipment is installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1, or;

(ii) any device or method, approved by the commission or its delegate, which yields accurate measurements of crude oil or condensate.

(C) Adjustments to the quantities determined by the methods described in subparagraphs (A) or (B) of this paragraph shall be made for temperature from the nearest whole number degree to the basis of 60 degrees Fahrenheit and to the nearest 5/10 API degree gravity in accordance with the volume correction Tables 5A and 6A contained in API Standard 2540, American Society for Testing Materials 01250, Institute of Petroleum 200, first edition, August 1980. A pipeline may deduct the basic sediment, water, and other impurities as shown by the centrifugal or other test agreed upon by the shipper and pipeline; and 1.0% for evaporation and loss during transportation. The net balance shall be the quantity deliverable by the pipeline. In allowing the deductions, it is not the intention of the commission to affect any tax or royalty obligations imposed by the laws of Texas on any producer or shipper of crude oil.

(D) A transfer of custody of crude between transporters is subject to measurement as agreed upon by the transporters.

(10) Delivery and demurrage. Each pipeline shall transport oil with reasonable diligence, considering the quality of the oil, the distance of transportation, and other material elements, but at any time after receipt of a consignment of oil, upon 24 hours' notice to the consignee, may offer oil for delivery from its common stock at the point of destination, conformable to paragraph (6) of this section, at a rate not exceeding 10,000 barrels per day of 24 hours. Computation of time of storage (as provided for in paragraph (5) of this section) shall begin at the expiration of such notice. At the expiration of the time allowed in paragraph (5) of this section for storage at destination, a pipeline may assess a demurrage charge on oil offered for delivery and remaining undelivered, at a rate for the first 10 days of $.001 per barrel; and thereafter at a rate of $.0075 per barrel, for each day of 24 hours or fractional part thereof.

(11) Unpaid charges, lien for and sale to cover. A pipeline shall have a lien on all oil to cover charges for transportation, including demurrage, and it may withhold delivery of oil until the charges are paid. If the charges shall remain unpaid for more than five days after notice of readiness to deliver, the pipeline may sell the oil at public auction at the general office of the pipeline on any day not a legal holiday. The date for the sale shall be not less than 48 hours after publication of notice in a daily newspaper of general circulation published in the city where the general office of the pipeline is located. The notice shall give the time and place of the sale, and the quantity of the oil to be sold. From the proceeds of the sale, the pipeline may deduct all charges lawfully accruing, including demurrage, and all expenses of the sale. The net balance shall be paid to the person lawfully entitled thereto.

(12) Notice of claim. Notice of claims for loss, damage, or delay in connection with the shipment of oil must be made in writing to the pipeline within 91 days after the damage, loss, or delay occurred. If the claim is for failure to make delivery, the claim must be made within 91 days after a reasonable time for delivery has elapsed.

(13) Telephone-telegraph line--shipper to use. If a pipeline maintains a private telegraph or telephone line, a shipper may use it without extra charge, for messages incident to shipments. However, a pipeline shall not be held liable for failure to deliver any messages away from its office or for delay in transmission or for interruption of service.

(14) Contracts of transportation. When a consignment of oil is accepted, the pipeline shall give the shipper a run ticket, and shall give the shipper a statement that shows the

amount of oil received for transportation, the points of origin and destination, corrections made for temperature, deductions made for impurities, and the rate for such transportation.

(15) Shipper's tanks, etc.--inspection. When a shipment of oil has been offered for transportation the pipeline shall have the right to go upon the premises where the oil is produced or stored, and have access to any and all tanks or storage receptacles for the purpose of making any examination, inspection, or test authorized by this section.

(16) Offers in excess of facilities. If oil is offered to any pipeline for transportation in excess of the amount that can be immediately transported, the transportation furnished by the pipeline shall be apportioned among all shippers in proportion to the amounts offered by each; but no offer for transportation shall be considered beyond the amount which the person requesting the shipment then has ready for shipment by the pipeline. The pipeline shall be considered as a shipper of oil produced or purchased by itself and held for shipment through its line, and its oil shall be entitled to participate in such apportionate.

(17) Interchange of tonnage. Pipelines shall provide the necessary connections and facilities for the exchange of tonnage at every locality reached by two or more pipelines, when the commission finds that a necessity exists for connection, and under such regulations as said commission may determine in each case.

(18) Receipt and delivery--necessary facilities for. Each pipeline shall install and maintain facilities for the receipt and delivery of marketable crude petroleum of shippers at any point on its line if the commission finds that a necessity exists therefor, and under regulations by the commission.

(19) Reports of loss from fires, lightning, and leakage.

(A) Each pipeline shall immediately notify the commission district office, electronically or by telephone, of each fire that occurs at any oil tank owned or controlled by the pipeline, or of any tank struck by lightning. Each pipeline shall in like manner report each break or leak in any of its tanks or pipelines from which more than five barrels escape. Each pipeline shall file the required information with the commission in accordance with the appropriate commission form within 30 days from the date of the spill or leak.

(B) No risk of fire, storm, flood, or act of God, and no risk resulting from riots, insurrection, rebellion, war, or act of the public enemy, or from quarantine or authority of law or any order, requisition or necessity of the government of the United States in time of war, shall be borne by a pipeline, nor shall any liability accrue to it from any damage thereby occasioned. If loss of any crude oil from any such causes occurs after the oil has been received for transportation, and before it has been delivered to the consignee, the shipper shall bear a loss in such proportion as the amount of his shipment is to all of the oil held in transportation by the pipeline at the time of such loss, and the shipper shall be entitled to have delivered only such portion of his shipment as may remain after a deduction of his due proportion of such loss, but in such event the shipper shall be required to pay charges only on the quantity of oil delivered. This section shall not apply if the loss occurs because of negligence of the pipeline.

(C) Common carrier pipelines shall mail (return receipt requested) or hand deliver to landowners (persons who have legal title to the property in question) and residents (persons whose mailing address is the property in question) of land upon which a spill or leak has occurred, all spill or leak reports required by the commission for that particular spill or leak within 30 days of filing the required reports with the commission. Registration with the commission by landowners and residents for the purpose of receiving spill or leak reports shall be required every five years, with renewal registration starting January 1, 1999. If a landowner or resident is not registered with the commission, the common carrier is not required to furnish such reports to the resident or landowner.

(20) Printing and posting. Each pipeline shall have paragraphs (1) - (19) of this section printed on its tariff sheets, and shall post the printed sections in a prominent place in its various offices for the inspection of the shipping public. Each pipeline shall post and publish only such rules and regulations as may be adopted by the commission as general rules or such special rules as may be adopted for any particular field.

(21) Immediately upon the publication of its tariffs, and each subsequent amendment thereof, each pipeline is requested to file one copy with the commission.

(22) Records.

(A) Each person operating crude oil gathering, transportation, or storage facilities in the state must maintain daily records of the quantities of all crude oil moved from each oil field in the state, and such records shall also show separately for each field to whom delivery is made, and the quantities so delivered.

(B) The information contained in the records thus required to be kept must be reported to the commission by the gatherers, transporters, and handlers at such times and in such manner as may be required by the commission.

Source Note: The provisions of this §3.71 adopted to be effective August 25, 2003, 28 TexReg 6816.

§3.72 Obtaining Pipeline Connections

(a) A common carrier pipeline transporting crude oil in Texas, upon application for connection and offer of crude oil by a producer or persons owning unconnected lease batteries, shall connect such lease batteries in the following instances:

(1) when such request is made for connection of lease batteries in the general area served by a common carrier, which is an affiliate or subsidiary of a common purchaser,

as defined in the Texas Natural Resources Code, §111.081; and

(2) within individual fields, when any common carrier possesses the only pipeline serving such field or common reservoir and request is made for connection of an unconnected lease battery in the field, provided, that for just cause a common carrier pipeline may apply for an exception. If proper application has been made for such connection and the common carrier pipeline refuses to connect the unconnected lease battery, a complaint for failure to connect may be filed with the commission by the person seeking the connection. The complaining person may allege discrimination or noncompliance with the provisions of this subsection or the appropriate section(s) of the Texas Natural Resources Code.

(b) Whether the matter comes to the commission either as an application for exception by the pipeline or on a complaint for failure to connect, at least 10 days' notice shall be given to all interested parties, after which the hearing shall be held. At the hearing, the commission may require and consider, among other factors, evidence relating to ability of the pipeline carrier to transport the quality of oil, the market or lack of market for the proffered oil, and the period required to return the capital investment for the connection. It is not its intention to limit, nor does the commission herein limit, the consideration by it of any facts with respect to a claim of violation of, or of any facts that may constitute a cause of action for violation of, any of the provisions of Texas Natural Resources Code, §§11.001-11.136, whether enumerated in this section or not.

Source Note: The provisions of this §3.72 adopted to be effective August 25, 2003, 28 TexReg 6816.

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

(a) No pipeline or other carrier shall be connected with any well subject to the jurisdiction of the Commission until the operator of the well provides the pipeline or other carrier with a certificate from the Commission that the rules in this title have been complied with. This section shall not prevent a temporary connection with any well in order to take care of production and prevent waste until the operator has a reasonable time, not to exceed 30 days from the date of such connection, within which to obtain such certificate. For purposes of this section, the term "Commission" means the Railroad Commission of Texas, the Director of the Oil and Gas Division, or the Director's delegate.

(b) No pipeline operator shall physically disconnect its facilities from or cease providing pipeline services to any well or lease without first obtaining:

(1) written consent of the well or lease operator for the proposed disconnect or termination; or

(2) written permission from the Commission. This section does not apply to temporary suspensions of service authorized under other rules in this title or attributable to maintenance, safety, or product quality issues.

(c) If the pipeline operator is unable to obtain the written consent of the well or lease operator to physically disconnect from or cease providing service to the well or lease, or the well or lease operator objects to the proposed physical disconnect or termination of service, and the pipeline operator still desires to physically disconnect from or cease providing service to the well or lease, the pipeline operator shall file an application with the Commission requesting permission to physically disconnect its facilities from or cease providing service to the well or lease. An affected well or lease operator may object to physical disconnection or cessation of service and file a complaint with the Commission under this subsection.

(1) The pipeline operator shall file its application with the Commission at least 30 days prior to the date on which the pipeline operator desires to make the physical disconnection or cease providing service. On the same date as the pipeline operator files its application with the Commission, the pipeline operator shall send a copy of the application to the operator of the well or lease affected by the application by certified mail, return receipt requested. The application shall identify the well operator and pipeline operator, identify each lease or well involved, and provide sufficient information to allow the Commission to make a determination pursuant to paragraph (4) of this subsection.

(2) If the operator of the well or lease does not file with the Commission a written objection to the application within 28 days following the filing of the application, the Commission shall administratively approve or deny the application and shall notify the pipeline operator and the well or lease operator of the decision by certified mail, return receipt requested. Following such notification, either party shall have 21 days to file a written request for hearing. If neither party files a timely request for hearing, the administrative approval or denial shall be deemed final.

(3) If either party files a timely request for hearing, the Commission shall refer the application to the Office of General Counsel docket services to be set for hearing within 60 days following the date of referral.

(4) In determining whether or not to approve a request to physically disconnect from or cease providing service to a well or lease, the Commission may consider relevant factors, including but not limited to:

(A) operational integrity of the pipeline facilities;

(B) operational integrity of the equipment on the well or lease;

(C) cost of continued operation of the physical connection or service;

(D) risk to public safety, human health and the environment;

(E) availability of alternative transportation;

(F) protection of correlative rights; and

(G) prevention of waste.

(d) The Commission may shut in and seal any well, and cancel any certificate of compliance if it appears that the operator of a well has violated or is violating, in connection with the operation of the well, any statutes, rules in this title, permits, or orders of the Commission. Upon receipt of information that indicates operations are being conducted in violation of statutes, rules in this title, or a Commission permit or order, the Commission shall send a notice letter to the operator directing the operator to correct the violation. The letter shall state the facts or conduct alleged to warrant the shut-in and sealing of the well, and cancellation of the certificate of compliance. The letter shall give the operator an opportunity to show compliance with the statutes, rules in this title, or Commission permits or orders. The letter shall be sent by registered or certified mail, and shall indicate the time within which compliance shall be demonstrated or achieved. The time period allowed for the operator to achieve compliance shall not be less than 10 days from the date the notice letter is sent.

(e) Within the time period set out in the notice letter, the operator shall either demonstrate compliance or correct the violation, and notify the Commission of its action.

(f) If the violation is not corrected within the time period set out in the notice letter, the Commission may shut in and seal the well, and cancel the certificate of compliance.

(g) If a certificate of compliance has been cancelled, the Commission may not issue a new certificate of compliance until the owner or operator of the property covered by the certificate of compliance submits to the Commission a reissuance fee as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78); and

(1) the property covered by the certificate is brought into compliance with the statutes, rules in this title, and Commission permits and orders; or

(2) the Commission determines that there are just and equitable grounds for reissuing the certificate.

(h) Pursuant to Texas Natural Resources Code, §91.705, upon notice from the Commission to any operator of a pipeline or other carrier connected to any well subject to the jurisdiction of the Commission that the certificate of compliance applicable to the well has been canceled by the Commission, the operator of the pipeline or other carrier shall disconnect from or suspend service to the well and shall not reconnect to or resume service to that well until a new certificate of compliance has been issued by the Commission. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(i) Pursuant to Texas Natural Resources Code, §91.706(a), upon notice from the Commission that a certificate of compliance as to any well has been canceled as provided in this section, the operator of such well shall not use that well for production, injection, or disposal until a new certificate of compliance with respect to the well has been issued by the Commission as provided in this section. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

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

(k) The provisions of this section shall be cumulative of other Commission actions and procedures relating to violations of state statutes or Commission permits, rules, and orders, including the authority of the Commission to immediately shut in a well or lease, or to direct the operator to shut in a well or lease, when an emergency exists due to pollution or an imminent threat of harm to people or property.

Source Note: The provisions of this §3.73 adopted to be effective October 28, 2003, 28 TexReg 9241; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective November 26, 2007, 32 TexReg 8452.

§3.76 Commission Approval of Plats for Mineral Development

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

(1) Minerals--Oil and/or gas.

(2) Operations site--A surface area of two or more acres that an owner of a possessory mineral interest may use to explore for and produce minerals, which is located in whole or in part within a qualified subdivision, and designated on the subdivision plat.

(3) Possessory mineral interest--A mineral interest that includes the right to use the land surface for exploration and production of minerals.

(4) Qualified subdivision--A tract of land not more than 640 acres:

(A) that is located in a county having a population in excess of 400,000, or in a county having a population in excess of 140,000 that borders a county having a population in excess of 400,000 or located on a barrier

island;

(B) that has been subdivided in a manner authorized by law by the surface owners for residential, commercial, or industrial use; and

(C) that contains an operations site for each separate 80 acres within the 640-acre tract and provisions for road and pipeline easements to allow use of the operations sites.

(5) Barrier island--An island bordering on the Gulf of Mexico and entirely surrounded by water.

(b) As provided in subsections (e) and (f) of this section, the surface owners of a parcel of land may restrict use of the surface by the possessory mineral owners if the tract is a qualified subdivision and if a plat of the subdivision has been approved by the Railroad Commission after notice and hearing and filed with the clerk of the county in which the qualified subdivision is to be located.

(c) An application for a hearing under this section must be made in writing and mailed or delivered to the director of the Oil and Gas Division. The application must include:

(1) a jurisdictional statement setting out the facts stated in subsection (a)(4)(A) and (B) of this section;

(2) a statement that the applicant has authority to represent and represents all surface owners of land contained in the proposed qualified subdivision;

(3) the names and addresses of all owners of possessory mineral interests and all mineral lessors of land contained in the proposed qualified subdivision;

(4) a plat of the proposed subdivision showing each proposed 80-acre tract with its operations site, road easements, and pipeline easements and a legible copy thereof no larger than 8 1/2 inches by 11 inches;

(5) a concise description of mineral development in the area, including the number of oil and/or gas wells within 2.5 miles of the boundary of the proposed qualified subdivision and the depths at which each well is completed;

(6) a list of all the Railroad Commission designated oil and/or gas fields, if any, which underlie the proposed qualified subdivision; including the spacing and density requirements. If no Railroad Commission designated fields underlie the qualified subdivision, the application should so state.

(d) The Railroad Commission shall, on proper notice to the applicant and owners of possessory mineral interests and mineral lessors of land contained in the proposed qualified subdivision, hold a hearing on the application to determine the adequacy of the number and location of operations sites and road and pipeline easements. At the hearing on the application, evidence may be presented by the applicant and the owners of possessory mineral interests and mineral lessors. The applicant must carry the burden of proof. After considering the evidence, the commission may approve, reject, or amend the application to ensure that the mineral resources of the subdivision may be fully and effectively developed.

(e) An owner of a possessory mineral interest within a Railroad Commission approved qualified subdivision may use only the surface contained in designated operations sites for exploration, development, and production of minerals and only the designated easements as necessary to adequately use the operations sites.

(f) The owner of the possessory mineral interest may drill wells or extend well bores from an operations site or from a site outside of the qualified subdivision to bottomhole locations vertically beneath the surface of parts of the qualified subdivision other than the operation sites. Such drilling is subject to other applicable commission rules and regulations, and is permissible only to the extent that the operations do not unreasonably interfere with the use of the surface of the qualified subdivision outside the operations site.

(g) Subsections (e) and (f) of this section cease to apply to a subdivision if, by the third anniversary of the date on which the order of the commission becomes final:

(1) the surface owner has not commenced actual construction of roads or utilities within the qualified subdivision; and

(2) a lot within the qualified subdivision has not been sold to a third party.

(h) All or any portion of a qualified subdivision may be amended, replatted, or abandoned by the surface owner. An amendment or replat, however, may not alter, diminish, or impair the usefulness of an operations site or appurtenant road or pipeline easement unless the amendment or replat is approved by the commission. Railroad Commission approval of a replat or amendment may be administratively granted by the director of the Oil and Gas Division, or his delegate, upon submission of items required in subsection (c) of this section and after notice and opportunity for hearing has been afforded to all possessory mineral interest owners and mineral lessors of land contained within the original and/or replatted or amended qualified subdivision.

Source Note: The provisions of this §3.76 adopted to be effective July 10, 2000, 25 TexReg 6487.

§3.78 Fees and Financial Security Requirements

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

(1) Violation--Noncompliance with a Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(2) Outstanding violation--A violation for which:

(A) either:

(i) a Commission order finding a violation has been entered and all appeals have been exhausted; or

(ii) an agreed order between the Commission and the organization relating to a violation has been entered; and

(B) one or more of the following conditions still exist:

(i) the conditions that constituted the violation have not been corrected;

(ii) all administrative, civil, and criminal penalties, if any, relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid; or

(iii) all reimbursements of any costs and expenses assessed by the Commission relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid.

(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

(4) Financial security--An individual performance bond, blanket performance bond, letter of credit, or cash deposit filed with the Commission.

(5) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(A) located in or on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which requires plugging by means other than conventional land-based methods, including, but not limited to, use of a barge, use of a boat, dredging, or building a causeway or other access road to bring in the necessary equipment to plug the well; or,

(B) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(6) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(7) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(8) Officers and owners--Any persons owning or controlling an organization including officers, directors, general partners, sole proprietors, owners of more than 25% ownership interest, any trustee of an organization, and any person determined by a final judgment or final administrative order to have exercised control over the organization.

(9) Letter of credit--An irrevocable letter of credit issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party bank authorized under state or federal law to do business in Texas; and

(C) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the Commission or its authorized delegate.

(10) Bond--A surety instrument issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party corporate surety authorized under state law to issue surety bonds in Texas; and

(C) renewed and continued in effect until the conditions of the bond have been met or its release is approved by the Commission or its authorized delegate.

(11) Well-specific plugging insurance policy--An insurance policy that:

(A) is approved by the Texas Department of Insurance;

(B) is issued by an insurer authorized under state law to issue a well-specific plugging insurance policy in Texas;

(C) names the Commission as the owner and contingent beneficiary of the policy;

(D) names a primary beneficiary who agrees to plug the specified well bore;

(E) is fully prepaid and cannot be canceled or surrendered;

(F) provides that the policy continues in effect until the well bore has been plugged as required by the Commission;

(G) provides that benefits will be paid when, but not before, the specified well bore has been plugged; and

(H) provides that benefits that will equal or exceed:

(i) $2 per foot for each foot of well depth for land wells;

(ii) $60,000 for bay wells; or

(iii) $100,000 for offshore wells.

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

(13) Escrow funds--Funds deposited with the Commission as part of an application for a plugging extension for an inactive land well.

(14) Groundwater protection determination letter--A letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.011.

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

(1) With each application or materially amended application for a permit to drill, deepen, plug back, or reenter a well, the applicant shall submit to the Commission a nonrefundable fee of:

(A) $200 if the proposed total depth of the well is 2,000 feet or less;

(B) $225 if the proposed total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(C) $250 if the proposed total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet; or

(D) $300 if the proposed total depth of the well is greater than 9,000 feet.

(2) An application for a permit to drill, deepen, plug back, or reenter a well will be considered materially amended if the amendment is made for a purpose other than:

(A) to add omitted required information;

(B) to correct typographical errors; or

(C) to correct clerical errors.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the Commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(4) With each individual application for an exception to any rule or rules in this chapter, the applicant shall submit to the Commission a nonrefundable fee of $150, except as provided in paragraph (5) of this subsection.

(5) With each application for an exception to any rule or rules in this chapter that includes an exception to §3.37 of this title (relating to Statewide Spacing Rule) (Statewide Rule 37) or §3.38 of this title (relating to Well Densities) (Statewide Rule 38), the applicant shall submit a nonrefundable fee of $200.

(6) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the Commission a nonrefundable fee of $100 per well.

(7) With each application for a fluid injection well permit, the applicant shall submit to the Commission a nonrefundable fee of $200 per well. Fluid injection well means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well.

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

(9) If a certificate of compliance for an oil lease or gas well has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) (Statewide Rule 58).

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

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

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

(13) Inactive well extension fee.

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

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

(14) Groundwater protection determination letters.

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

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

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

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

(c) Organization Report Fee. An organization report required by Texas Natural Resources Code, §91.142, shall be accompanied by a fee as follows:

(1) for an operator of:

(A) not more than 25 wells, $300;

(B) more than 25 but not more than 100 wells, $500; or

(C) more than 100 wells, $1,000;

(2) for an operator of one or more natural gas pipelines, $225;

(3) for an operator of one or more of the following service activities: pollution cleanup contractor; directional surveying; approved cementer for plugging wells; a cementer of casing strings or liners; or physically moving or storing crude or condensate, $300;

(4) for an operator of one or more liquids pipelines, $625;

(5) for an operator of all other service activities, or facilities, $500;

(6) for an operator with multiple activities, a total fee equal to the sum of the separate fees applicable to each category of service activity, facility, pipeline, or number of wells operated shall be submitted, provided that the total fee for an operator of wells shall not exceed $1,125; and

(7) for an entity not currently performing operations under the jurisdiction of the Commission, $300.

(d) Financial security. Except for those operators exempted under subsection (g)(7) of this section, any person, including any firm, partnership, joint stock association, corporation, or other organization, required by Texas Natural Resources Code, §91.142, to file an organization report with the Commission must also file financial security in one of the following forms:

(1) an individual performance bond;

(2) a blanket performance bond; or

(3) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.

(e) Forms for financial security and insurance policies. Operators shall submit well-specific plugging insurance policies, bonds and letters of credit on forms prescribed by the Commission.

(f) Filing deadlines for financial security and insurance policies. Operators shall submit required financial security or well-specific plugging insurance policies at the time of filing an initial organization report, as a condition of the issuance of a permit to drill, recomplete or reenter, upon yearly renewal, or as otherwise required under this section.

(g) Amount of financial security. An operator required to file financial security under subsection (d) of this section shall file financial security described in this subsection.

(1) Types and amounts of financial security required.

(A) A person operating one or more wells may file

an individual performance bond, letter of credit, or cash deposit in an amount equal to the sum of $2.00 for each foot of total well depth for each well operated, excluding any well bore included in a well-specific plugging insurance policy.

(B) A person operating one or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the sum of the base amount determined by the total number of wells operated excluding any well bores and/or permits issued to drill, recomplete, or reenter wells included in a well-specific plugging insurance policy. A person performing multiple operations shall be required to file only one blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility, in which case the person also shall comply with the financial security requirements of subsection (l) of this section. The financial security amount shall be at least the base amount determined by the total number of wells operated or $25,000, whichever is greater. After excluding any well bores and/or permits issued to drill, recomplete or reenter wells included in a well-specific plugging insurance policy, the base amount is determined as follows:

(i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000.

(ii) The base amount for a person operating more than 10 but fewer than 100 wells shall be $50,000.

(iii) The base amount for a person operating 100 or more wells shall be $250,000.

(2) Additional financial security for bay wells.

(A) All operators of bay wells shall file additional financial security of no less than $60,000 in addition to any other financial security that is required under this section for any other Commission-regulated activities.

(B) For each bay well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file additional financial security of $60,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $60,000. An operator shall not be required to file additional financial security in addition to the $60,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive bay well.

(C) In the case of a bay well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain subject to the provisions of subparagraph (B) of this paragraph, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(3) Additional financial security for offshore wells.

(A) All operators of offshore wells and operators of both bay wells and offshore wells shall file additional financial security of no less than $100,000 in addition to any other financial security that is required under this section for any other Commission regulated activities.

(B) For each offshore well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file an additional amount of financial security of $100,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $100,000. An operator shall not be required to file additional financial security in addition to the $100,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive offshore well.

(C) In the case of an offshore well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain classified as inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(4) Reduction of the additional financial security that is required for bay and/or offshore wells. An operator may request a reduction of either the additional $60,000 in financial security required for all operators of bay wells, or the additional $100,000 in financial security required for all operators of offshore wells and operators of both bay wells and offshore wells.

(A) The director may administratively approve the reduction if the operator provides documentation that it currently has acceptable financial assurance in place to satisfy any financial assurance requirements established by local authorities. The operator must show that the bond or other form of financial assurance can be called on by or assigned to the Commission under the following circumstances:

(i) a well is likely to pollute or is polluting any ground or surface water or is allowing the uncontrolled escape of formation fluids from the strata in which they were originally located; or

(ii) a well is not being maintained in compliance with Commission rules or state law relating to plugging or the prevention or control of pollution; or

(iii) the operator has failed to renew and maintain an organization report filing as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) and this section.

(B) If the director administratively denies a requested reduction, the operator may request a hearing to determine whether the reduction should be granted.

(5) Reduction in additional financial security required

for bay and/or offshore wells that are not actively producing oil and natural gas. An operator may request that Commission consider a reduction in any additional financial security requirement for the operation of bay and/or offshore wells that are not actively producing oil and natural gas or that are used for disposal or injection in an amount not to exceed the remainder of 25% of the operator's certified net worth based on the independently audited calculation for the most recently completed fiscal year minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and/or offshore wells.

(A) The director may administratively grant a full or partial reduction if the operator meets the following criteria:

(i) the operator has either five or fewer bay and offshore wells or at least half of the operator's bay and offshore wells are actively producing oil and natural gas;

(ii) the operator provides to the Commission certification of its net worth from an independent auditor that has employed generally accepted accounting principles to confirm the operator's stated net worth based on the most recently available and independently audited calculation;

(iii) the reduction is less than or equal to the remainder of 25% of the operator's certified net worth minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and offshore wells;

(iv) none of the operator's wells or operations, including any land-based wells, have been found by Commission staff to be violating or to have violated any Commission rule that resulted in pollution or in any hazard to the health or safety of the public in the last 12 months.

(B) If the director administratively denies the requested reduction, an operator may request a hearing to determine if a full or partial reduction should be granted.

(C) The operator may also request a hearing to challenge the Commission's presumed estimate of the operator's plugging liability for bay and offshore wells as applied to any additional financial security required for any inactive bay and offshore wells. The operator shall present clear and convincing evidence that the estimated plugging liability is less than the amount estimated by the Commission. Notice of the hearing shall be provided by the Commission to the owners of the surface estate and the owners of the mineral estate for any well that is a subject of the requested hearing, and all other affected persons as identified by the operator or otherwise required by the Commission.

(6) Persons with non-well operations not exempted under paragraph (7) of this subsection. A person performing other operations who is not an operator of wells and who is not a person whose only activity is as a first purchaser, survey company, gas nominator, gas purchaser or well plugger shall file financial security in the amount of $25,000.

(7) Persons exempt from financial security requirements. No financial security is required of a person who is not an operator of wells if the person's only activity is as a first purchaser, survey company, salt water hauler, gas nominator, gas purchaser and/or well plugger.

(8) Persons with both well and non-well operations. If a person is engaged in more than one activity or operation, including well operation, for which financial security is required, the person is not required to file financial security for each activity or operation in which the person is engaged. The person is required to file financial security only in the greatest amount required for any activity or operation in which the person engages. The financial security filed covers all of the activities and operations for which financial security is required. The provisions of this paragraph do not exempt a person from the financial security required under subsection (l) of this section.

(9) Financial security amounts are the minimum amounts required by this section to be filed. A person may file a greater amount if desired.

(h) Financial security conditions. Any bond, letter of credit, or cash deposit required under this section is subject to the conditions that the operator will plug and abandon all wells and control, abate, and clean up pollution associated with the oil and gas operations and activities covered under the required financial security in accordance with applicable state law and permits, rules, and orders of the Commission. This section does not apply to a well-specific plugging insurance policy.

(i) Conditions for cash deposits and escrow funds. Operators must tender cash deposits and escrow funds in United States currency or certified cashiers check only. The Commission or its delegate will place all cash deposits and escrow funds in a special account within the Oil and Gas Regulation and Cleanup Fund account. The Commission or its delegate will deposit any interest accruing on cash deposits and escrow funds into the Oil and Gas Regulation and Cleanup Fund pursuant to Texas Natural Resources Code, §81.067. The Commission or its delegate may not refund a cash deposit until either financial security is accepted by the Commission or its delegate as provided for under this section or an operator ceases all activity. The Commission or its delegate may release escrow funds to the current operator of the well only if the well for which the operator tendered the escrow funds is either restored to active status or plugged in accordance with Commission rules. In the event that the well is plugged through the use of state funds, the Commission may collect from the escrow account in the amount necessary to reimburse the state for any expenditure.

(j) Well or lease transfer.

(1) The Commission shall not approve a transfer of operatorship submitted for any well or lease unless the

operator acquiring the well or lease has on file with the Commission financial security in an amount sufficient to cover both its current operations and the wells or leases being transferred.

(2) Any existing financial security covering the well or lease proposed for transfer shall remain in effect and the prior operator of the well remains responsible for compliance with all laws and Commission rules covering the transferred well until the Commission approves the transfer.

(3) A transfer of a well or lease from one entity to another entity under common ownership is a transfer for the purposes of this section.

(4) The Commission may approve a transfer of operatorship submitted for any well bore included in a well-specific plugging insurance policy if the transfer meets all other Commission requirements.

(k) Reimbursement liability. Filing any form of financial security does not extinguish a person's liability for reimbursement for the expenditure of state oilfield clean-up funds pursuant to Texas Natural Resources Code, §89.083 and 91.113.

(l) Financial security for commercial facilities. The provisions of this subsection shall apply to the holder of any permit for a commercial facility.

(1) Application.

(A) New permits. Any application for a new or amended commercial facility permit filed after the original effective date of this subsection shall include:

(i) a written estimate of the maximum dollar amount necessary to close the facility prepared in accordance with the provisions of paragraph (4) of this subsection that shows all assumptions and calculations used to develop the estimate;

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

(iii) information concerning the issuer of the bond or letter of credit as required under paragraph (5) of this subsection including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.

(B) Existing permits. Within 180 days of the original effective date of this subsection, the holder of any commercial facility permit issued on or before the original effective date of this subsection shall file with the Commission the information specified in subparagraph (A)(i) - (iii) of this paragraph.

(2) Notice and hearing.

(A) New permits. For commercial facility permits issued after the original effective date of this subsection, the provisions of §3.8 or §3.57 of this title (relating to Water Protection; and Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials), as applicable, regarding notice and opportunity for hearing, shall apply to review and approval of financial security proposed to be filed to meet the requirements of this subsection.

(B) Existing permits. Notice of filing of information required under paragraph (1)(B) of this subsection shall not be required. In the event approval of the financial security proposed to be filed for a commercial facility operating under a permit in effect as of the original effective date of this subsection is denied administratively, the applicant shall have the right to a hearing upon written request. After hearing, the examiner shall recommend a final action by the Commission.

(3) Filing of instrument.

(A) New permits. A commercial facility permitted after the original effective date of this subsection may not receive oil field fluids or oil and gas waste until a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with the Commission.

(B) Existing permits. Except as otherwise provided in this subsection, after one year from the original effective date of this section, a commercial facility permitted on or before the original effective date of this subsection may not continue to receive oil field fluids or oil and gas waste unless a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the Commission or its delegate.

(C) Extensions for existing permits. On written request and for good cause shown, the Commission or its delegate may authorize a commercial facility permitted before the original effective date of this subsection to continue to receive oil field fluids or oil and gas waste after one year after the original effective date of this section even though financial security required under this subsection has not been filed. In the event the Commission or its delegate has not taken final action to approve or disapprove the amount of financial security proposed to be filed by the owner or operator under this subsection one year after the original effective date of the section, the period for filing financial security under this subsection is automatically extended to a date 45 days after such final Commission action.

(4) Amount.

(A) Except as provided in subparagraphs (B) or (C) of this paragraph, the amount of financial security required to be filed under this subsection shall be an amount based on a written estimate approved by the Commission or its delegate as being equal to or greater

than the maximum amount necessary to close the commercial facility, exclusive of plugging costs for any well or wells at the facility, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit, but shall in no event be less than $10,000.

(B) The owner or operator of one or more commercial facilities may reduce the amount of financial security required under this subsection for one such facility by the amount, if any, it filed as financial security under subsection (g)(6) of this section. The full amount of financial security required under subparagraph (A) of this paragraph shall be required for the remaining commercial facilities.

(C) Except for the facilities specifically exempted under subparagraph (D) of this paragraph, a qualified professional engineer licensed by the State of Texas shall prepare or supervise the preparation of a written estimate of the maximum amount necessary to close the commercial facility as provided in subparagraph (A) of this paragraph. The owner or operator of a commercial facility shall submit the written estimate under seal of a qualified licensed professional engineer to the Commission as required under paragraph (1) of this subsection.

(D) A facility permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials) that does not utilize on-site waste storage or disposal that requires a permit under §3.8 of this title (relating to Water Protection) is exempt from subparagraph (C) of this paragraph.

(E) Notwithstanding the fact that the maximum amount necessary to close the commercial facility as determined under this paragraph is exclusive of plugging costs, the proceeds of financial security filed under this subsection may be used by the Commission to pay the costs of plugging any well or wells at the facility if the financial security for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.

(5) Issuer and form.

(A) Bond. The issuer of any commercial facility bond filed in satisfaction of the requirements of this subsection shall be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection shall provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the Commission or its delegate.

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

(m) Effect of outstanding violations.

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

(A) the organization has outstanding violations; or

(B) an officer or owner of the organization, as defined in subsection (a) of this section, was, within seven years preceding the filing of the report, application, or certificate, an officer or owner of an organization and during that period, the organization committed a violation that remains an outstanding violation.

(2) The Commission shall accept a report or application or approve a certificate filed by an organization covered by paragraph (1) of this subsection if:

(A) the conditions that constituted the violation have been corrected or are being corrected in accordance with a schedule agreed to by the organization and the Commission;

(B) all administrative, civil, and criminal penalties, and all plugging and cleanup costs incurred by the state relating to those conditions have been paid or are being paid in accordance with a schedule agreed to by the organization and the Commission; and

(C) the report, application or certificate is in compliance with all other requirements of law and Commission rules.

(3) All fees tendered in connection with a report or application that is rejected under this subsection are nonrefundable.

(n) Mandatory surcharges. The Commission adopts this subsection pursuant to Texas Natural Resources Code, §81.070, to impose reasonable surcharges as necessary on fees collected by the Commission that are required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund, as provided by Texas Natural Resources Code, §81.067, in an amount sufficient to enable the Commission to recover the costs of performing the functions specified by Texas Natural Resources Code, §81.068, from those fees and surcharges. This subsection establishes the methodology the Commission shall use to determine the amount of the surcharge on each fee, as required by Texas Natural Resources Code, §81.070(c).

(1) For all fees subject to a surcharge under this section, the Commission shall employ a projected cost-based recovery methodology derived from budgeted cost

projections approved by the Legislature in the General Appropriations Act, which is dependent upon revenue projections issued by the Comptroller in the most recent Biennial Revenue Estimate. In establishing the surcharge amounts, the Commission shall consider the factors and values set forth in the following subparagraphs.

(A) The Commission shall ascertain the time required to complete the regulatory work associated with the activity in connection with which the surcharge is imposed using the number of full-time equivalent positions (FTEs) appropriated by the Legislature for that purpose during the applicable biennium, multiplied by the work hours in a fiscal year, divided by the anticipated number of permit applications processed in a fiscal year.

(B) The Commission shall use the number of P-5 Organization Reports as a proxy to determine the number of individual or entities from which the Commission's costs may be recovered. An Organization Report is required to be filed and renewed annually by any organization, including any person, firm, partnership, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, that performs operations within the jurisdiction of the agency.

(C) The Commission shall determine how the surcharge will affect operators considered to be large, based on operating more than 10,000 oil or gas wells; operators considered to be medium, based on operating more than 1,000 oil or gas wells, but fewer than 10,000 wells; and operators considered to be small, based on operating fewer than 1,000 oil or gas wells.

(D) The Commission shall consider the balance of the Oil and Gas Regulation and Cleanup Fund at the beginning of the fiscal year in which the surcharge is assessed.

(E) The Commission shall assume that the Legislature intended that the agency's oil and gas regulatory program should be self-funded. The Commission shall maintain an adequate balance in the Oil and Gas Regulation and Cleanup Fund such that the regulatory program can withstand a decrease in industry activity without sacrificing the health and public safety aspects of its regulatory work, while also having funds available to respond to any emergency related to oil and gas activity throughout the state. The Commission shall also maintain a fund balance that is within the statutory fund limits as determined by the Legislature.

(2) The Commission shall consider the factors set forth in paragraph (1) of this subsection to determine the surcharge applicable to all fees deposited to the Oil and Gas Regulation and Cleanup Fund in the following manner:

(A) the Commission shall first apply the premise that the oil and gas regulatory program should be self-funded;

(B) the Commission shall then apply a cost-based recovery analysis to the funding levels determined by the Legislature. The Commission shall rely primarily on these two factors, but shall also review all factors and values set forth in subparagraph (A) of this paragraph; and

(C) the Commission will apply the surcharge rate to all applicable fees as detailed in paragraph (3) of this subsection.

(3) Based on the factors and methodology set forth in this subsection, the Commission has determined that a surcharge rate of 150 percent will be necessary on all fees required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund.

(4) The Commission shall review the surcharge rate determination under this subsection periodically but not less than each biennium to confirm that the imposed surcharge is reasonable.

Source Note: The provisions of this §3.78 adopted to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective October 12, 2003, 28 TexReg 8890; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective December 19, 2005, 30 TexReg 8426; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective May 1, 2012, 37 TexReg 1315; amended to be effective August 27, 2012, 37 TexReg 6538; amended to beeffective December 16, 2013, 38 TexReg 9010; amended to be effective February 1, 2016, 41 TexReg 792.

§3.79 Definitions

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

(1) Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

(2) By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation.

(3) Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

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

(5) Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(7) District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

(8) Dry gas--Any natural gas produced from a stratum that does not produce crude petroleum oil.

(9) Exploratory well--Any well drilled for the purpose of securing geological or geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal and uranium, and includes what is commonly referred to in the industry as "slim hole tests," "core hole tests," or "seismic holes." For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(10) Gas lift--Gas lift by the use of gas not in solution with oil produced.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(12) Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

(13) Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water;

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(C) Heat or other associated energy found in geothermal formations;

(D) Any by-product derived from them.

(14) Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6 degrees Fahrenheit per 100 feet of depth.

(15) Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state.

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its

maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 8,000 feet. (Reference Order Number 20-59,200, effective May 1, 1969.)

(16) Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

(17) Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

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

(20) Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

(21) Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

(22) Sour gas--Any natural gas containing more than 1 1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(23) Sweet gas--All natural gas except sour gas and casinghead gas.

(24) Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code §§1301-1315); and

(B) the area seaward of such three league area owned by the United States.

(25) Transportation or to transport--The movement of any crude petroleum oil or products of crude petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

(26) Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

(27) Underground source of drinking water--An aquifer or its portion which is not an exempt aquifer as defined in 40 Code of Federal Regulations §146.4 and which:

(A) supplies any public water system; or

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

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

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

Source Note: The provisions of this §3.79 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.80 Commission Oil and Gas Forms, Applications, and Filing Requirements

(a) Forms. Forms required to be filed at the Commission shall be those prescribed by the Commission. A complete set of all Commission forms required to be filed at the Commission shall be kept by the Commission secretary and posted on the Commission's web site. Notice of any new or amended forms shall be issued by the Commission. For any required or discretionary filing, an organization may either file the prescribed form on paper or use any electronic filing process in accordance with subsections (e) or (f) of this section, as applicable. The Commission may

at its discretion accept an earlier version of a prescribed form, provided that it contains all required information and meets the requirements of subsection (e)(3) of this section.

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

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

(2) Electronic filing process--An electronic transmission to the Commission in a prescribed form and/or format authorized by the Commission and completed in accordance with Commission instructions.

(3) Form--A printed or typed paper document or electronic submission, including any necessary instructions, with blank spaces for insertion of required or requested specific information.

(4) Organization--Any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission.

(5) Position of ownership or control--A person holds a position of ownership or control in an organization if the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of an organization which is a sole proprietorship;

(D) the owner of more than a 25 percent ownership interest in the organization; or

(E) the designated trustee of the organization.

(6) Violation--Non-compliance with a statute, Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(c) Organization eligibility. The Commission may not accept an organization report or an application for a permit, or approve a certificate of compliance if:

(1) the organization that submitted the report, application, or certificate violated a statute or Commission rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) any person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization, and during that period of ownership or control the other organization violated a statute or Commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(d) Violations. An organization has committed a violation if there is either a Commission order against an organization finding that the organization has committed a violation and all appeals have been exhausted or an agreed order entered into by the Commission and an organization relating to an alleged violation, and:

(1) the conditions that constituted the violation or alleged violation have not been corrected;

(2) all administrative, civil and criminal penalties, if any, relating to the violation or agreed settlement relating to an alleged violation have not been paid; or

(3) all reimbursements of costs and expenses, if any, assessed by the Commission relating to the violation or to the alleged violation have not been collected.

(e) Authorization and standards for electronic filing.

(1) An organization may file electronically any form for which the Commission has provided an electronic version, provided that the organization pays all required filing fees and complies with all requirements, including but not limited to security procedures, for electronic filing.

(2) The Commission deems an organization that files electronically or on whose behalf is filed electronically any form, as of the time of filing, to have knowledge of and to be responsible for the information filed on the form, pursuant to the statutory requirements, restrictions, and standards found in and pertaining to:

(A) Texas Natural Resources Code, Title 3 (oil and gas well drilling, production, and plugging);

(B) Texas Natural Resources Code, Title 5 (geothermal resources);

(C) Texas Natural Resources Code, Title 11 (hazardous liquids storage);

(D) Texas Utilities Code, Chapter 121, Subchapter I (sour gas pipeline facilities);

(E) Texas Water Code, §26.131 (discharge permits);

(F) Texas Water Code, Chapter 27 (class II injection and disposal wells and class III brine mining wells);

(G) Texas Water Code, Chapter 29 (oil and gas waste haulers);

(H) Texas Health and Safety Code, §401.415 (oil and gas naturally occurring radioactive material (NORM) waste); and

(I) Texas Administrative Code, Title 16, Chapter 3 (Oil and Gas Division) and Chapter 4 (Environmental Protection).

(3) All forms that an organization submits or that are submitted on behalf of an organization shall be transmitted in the manner prescribed by the Commission that is compatible with its software, equipment, and facilities.

(4) The Commission may provide notice electronically to an organization of, and may provide an organization the ability to confirm electronically, the Commission's receipt of a form submitted electronically by or on behalf of that organization.

(5) The Commission deems that the signature of an organization's authorized representative appears on each form submitted electronically by or on behalf of the organization, as if this signature actually appears, as of the time the form is submitted electronically to the Commission.

(6) The Commission holds each organization responsible, under the penalties prescribed in Texas Natural Resources Code, §91.143, for all forms, information, or data that an organization files or that are filed on its behalf. The Commission charges each organization with the obligation to review and correct, if necessary, all forms or data that an organization files or that are filed on its behalf.

(f) Other electronic transmissions. The Commission may at its discretion accept other documents or data electronically transmitted.

Source Note: The provisions of this §3.80 adopted to be effective June 11, 2001, 26 TexReg 4088; amended to be effective April 12, 2004, 29 TexReg 3612; amended to be effective July 12, 2004, 29 TexReg 6633; amended to be effective October 11, 2004, 29 TexReg 9533; amended to be effective April 3, 2006, 31 TexReg 2846; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective January 7, 2008, 33 TexReg 114; amended to be effective September 12, 2011, 36 TexReg 5835; amended to be effective July 7, 2014, 39 TexReg 5148.

§3.81 Brine Mining Injection Wells

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

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

(2) Brine mining facility or facility--The brine mining injection well, and the pits, tanks, fresh water wells, pumps, and other structures and equipment that are or will be used in conjunction with the brine mining injection well.

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

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

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(6) Existing brine mining injection well--A brine mining injection well in which injection operations began prior to the effective date of this section.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(8) New brine mining injection well--A brine mining injection well in which injection operations begin on or after the effective date of this section.

(9) Permit--A written authorization issued by the commission under this section for the operation of a brine mining injection well.

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

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

(b) Prohibitions.

(1) Unauthorized injection. No person may operate a brine mining injection well without obtaining a permit from the commission under this section. No person may begin constructing a new brine mining injection well until the commission has issued a permit to operate the well under this section and a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(2) Fluid migration. No person may operate a brine mining injection well in a manner that allow fluids to escape from the permitted injection zone. If fluids are migrating from the permitted injection zone, the operator shall immediately cease injection operations.

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

(c) Standards for permit issuance. A permit may be issued only if the commission determines that the operation of the brine mining injection well will not result in the pollution of fresh water. All permits issued under this section will contain the conditions required by subsections (f) and (g) of this section, and all other conditions reasonably necessary to prevent the pollution of fresh water.

(d) Permit application.

(1) Duty to apply. Any person who operates or proposes to operate a brine mining injection well shall file a permit application with the commission in Austin within the time provided in paragraph (2) of this subsection. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the application is mailed or delivered to the commission in Austin. A permit application will be considered filed with the commission on the date it is received by the commission in Austin.

(2) Time to apply.

(A) Any person who proposes to operate a new brine mining injection well shall file a permit application at least 180 days before the date on which injection is to begin, unless a later date has been authorized by the director.

(B) Any person who is operating an existing brine injection well shall file a permit application within 90 days of the effective date of this section.

(C) Any person who has obtained a permit under this section and who wishes to continue to operate the brine mining injection well after the permit expires shall file an application for new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the director.

(3) Who applies. When a brine mining facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(4) Application requirements for all applicants. All applicants shall submit the following information, using application forms supplied by the commission:

(A) name, mailing address, and location of the brine mining facility for which the application is submitted;

(B) the operator's name, mailing address, telephone number, and status as federal, state, private, public, or other entity, and a statement indicating whether the operator is the owner of the facility;

(C) the proposed uses for the brine mined at the facility;

(D) a listing of all permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(E) a topographic map, or other map if the topographic map is unavailable, extending one mile beyond the property boundaries of the facility, depicting the facility and those springs, other surface water bodies, drinking water wells, and other wells listed in public records or otherwise known to the applicant within 1/4 mile of the facility property boundary;

(F) a plat showing the oil and gas operators of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the oil and gas operators;

(G) a plat showing the surface ownership of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the surface owners, as determined from the current county tax rolls or other reliable sources, and shall identify the source of the list. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the director may waive the requirements of this subparagraph with respect to those surface owners;

(H) a map with surveys marked showing the type, location, and depth of all wells of public record within a 1/4 mile radius of the brine mining injection well that penetrate the salt formation. The applicant shall attach the following information to the map:

(i) a tabulation of the wells showing the dates the wells were drilled and the present status of the wells; and

(ii) plugging records for plugged and abandoned wells and completion records for other wells;

(I) a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata should be protected;

(J) a complete electric log of the brine mining injection well or a nearby well. On the log, the applicant shall identify the geologic formations between the land surface and the top of the salt formation and the depths at which they occur;

(K) a drawing of the surface and subsurface construction details of the brine mining injection well;

(L) the proposed maximum daily injection rate and maximum injection pressure;

(M) the proposed injection procedure;

(N) the proposed mechanical integrity testing procedure;

(O) the source of mining water to be used at the facility. If the source is groundwater, the following information must be included:

(i) the groundwater formation name;

(ii) an depth of the groundwater formation; and

(iii) an analysis of the groundwater;

(P) the direction of the hydraulic gradient in the area; and

(Q) the proposed groundwater monitoring plan, or an alternate plan for assuring that fluids are not escaping from the permitted injection zone.

(5) Additional information. The applicant shall submit any other information required on the application form supplied by the commission. In addition to the information reported on the application form, the applicant shall submit, at the director's request, any other information the commission may reasonably require to assess the brine mining injection well and to determine whether to issue a permit.

(e) Signatories to applications and reports.

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

(A) for a corporation, by a responsible corporate officer. A responsible corporate officer means a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy-making or decision-making functions for the corporation; or

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

(2) Reports. All reports required by permits and other information requested by the commission shall be signed by a person described in paragraph (1) of this subsection or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in paragraph (1) of this subsection;

(B) the authorization specifies an individual or position having responsibility for the overall operation of the regulated facility; and

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

(3) Certification. Any person signing a document under paragraph (1) or (2) of this subsection shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information."

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

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

(2) Duty to reapply. If the operator wishes to continue a permitted activity after the expiration date of the permit, the operator shall apply for and obtain a new permit.

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

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

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

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

(7) Property rights. The permit does not convey any

property rights of any sort, or any exclusive privilege.

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

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

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

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

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

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

(10) Monitoring and records.

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

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

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

(11) Signatory requirements. All reports and other information submitted to the commission shall be signed and certified in accordance with subsection (e) of this section.

(12) Reporting requirements.

(A) The operator shall notify the commission as soon as possible of any planned physical alteration or addition to the facility.

(B) The operator shall give advance notice to the commission of any planned changes in the facility that may result in noncompliance with permit requirements.

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

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

(E) The operator shall report to the commission any noncompliance that may endanger human health or the environment.

(i) An oral report shall be made to the appropriate district office immediately after the operator becomes aware of the noncompliance. A written report shall be filed with the Austin office within five days of the time the operator becomes aware of the noncompliance. The written report must contain the following information:

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

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

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

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

(I) any monitoring or any other information that indicates that any contaminant may endanger fresh water; or

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

(F) The operator shall report any noncompliance not reported under subparagraphs (C), (D), and (E) of this paragraph at the time monitoring reports are submitted. The report must contain the information listed in subparagraph (E) of this paragraph.

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

(13) Transfers. The permit is not transferable to any person except by modification, or revocation and reissuance, to change the name of the operator and incorporate other necessary requirements.

(14) Completion report. Injection operations may not begin in any new brine mining injection well until the operator has submitted a completion report to the director, and the director has reviewed the completion report and found the well in compliance with the conditions of the permit.

(15) Workovers. The operator shall notify the appropriate district office at least 48 hours before performing any workover or corrective maintenance operations that involve the removal of the tubing or well stimulation.

(16) Mechanical integrity.

(A) No person may perform injection operations in a brine mining injection well that lacks mechanical integrity. A well has mechanical integrity if:

(i) there is not significant leak in the casing; and

(ii) there is no significant fluid movement into fresh water strata through vertical channels adjacent to the wellbore.

(B) For any existing brine mining injection well, mechanical integrity must be demonstrated annually. For any new brine mining injection well, mechanical integrity must be demonstrated before injection operations begin and annually thereafter. In addition, for all brine mining injections wells, mechanical integrity must be demonstrated after any workover that involves the removal of the tubing.

(C) To demonstrate the absence of a significant leak in the casing, the operator shall conduct a fluid pressure test in accordance with the following procedures:

(i) the operator shall submit a written test procedure to the commission in Austin at least 15 days before the test;

(ii) the operator shall notify the district office orally at least 48 hours before the test;

(iii) the operator shall perform the test using the test procedure submitted prior to the testing unless otherwise instructed by the commission; and

(iv) the operator shall file a complete record of the test with the commission in Austin within 30 days after the test.

(D) In lieu of an annual fluid pressure test, the operator may monitor the pressure of a hydrocarbon pad or blanket contained in the annulus space of the well, provided the operator has obtained written approval from the director prior to using this method.

(E) One of the following methods shall be used to demonstrate the absence of significant fluid movement into fresh water strata through vertical channels adjacent to the wellbore:

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

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

(F) The director may allow the use of a method of demonstrating mechanical integrity other than one listed in subparagraphs (C), (D), and (E) of this paragraph with the approval of the administrator of the Environmental Protection Agency obtained pursuant to 40 Code of Federal Regulations §146.8(d).

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

(17) Notice of conversion or abandonment. The operator shall notify the commission at such times as the permit requires before conversion or abandonment of the well.

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

(g) Other permit conditions. In addition to the conditions required in all permits, the commission will establish conditions, as required on a case-by-case basis, to provide for and assure compliance with the requirements specified in this subsection.

(1) Duration. Permits will be effective for a term up to the operating life of the facility. The commission will review each permit issued pursuant to this section at least once every five years to determine whether cause exists for modification, revocation and reissuance, or termination of the permit.

(2) Operating requirements. Permits will prescribe operating requirements, which will at a minimum specify that:

(A) except during well stimulation, injection pressure at the wellhead may not exceed a maximum calculated to assure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone; and

(B) in no case may the injection pressure initiate fractures in the confining zone or cause the escape of injection or formation fluids from the injection zone.

(3) Monitoring requirements. Permits will specify the following monitoring requirements:

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

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

(C) requirements to report monitoring results with a frequency dependent on the nature and effect of the monitored activity, but in no case less than quarterly.

(4) Construction requirements. Permits will specify construction requirements to assure that the injection operations will not endanger fresh water. Changes in construction requirements during construction may be approved by the director as minor modifications of the permit. No such changes may be physically incorporated into the construction of the well prior to approval of the modifications by the director.

(A) An existing brine mining injection well shall achieve compliance with the construction requirements according to a compliance schedule established as soon as possible and in no case later than one year after the effective date of the permit. The permit will require the operator to submit a written compliance report within 30 days after compliance has been achieved.

(B) A new brine mining injection well must be cased and cemented in accordance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements), (Rule 13), provided, however, that the operator shall set and cement surface casing in accordance with the letter obtained from the Groundwater Advisory Unit of the Oil and Gas Division pursuant to subsection (d)(4)(I) of this section regardless of the total depth of the well. No alternative program for setting less surface casing will be authorized.

(C) Appropriate logs and other tests must be conducted during the drilling and construction of a new brine mining injection well. A descriptive report interpreting the results of such logs and tests must be prepared by a knowledgeable log analyst and submitted to the director. The logs and tests appropriate to each well will be determined based on the depth, construction, and other characteristics of the well, the availability of similar data in the area, and the need for additional information that may arise from time to time as the construction of the well progresses.

(5) Financial responsibility. It shall be a permit condition that the operator maintain financial responsibility and resources to plug and abandon the brine mining injection well. The operator shall show evidence of such financial responsibility to the commission by submitting a surety bond or letter of credit in a form prescribed by the commission. Such bond or letter of credit shall be maintained until the well is plugged in accordance with subsection (f)(18) of this section.

(6) Corrective action. For all known wells that penetrate the injection zone within a 1/4 mile radius of the brine mining injection well and are improperly completed, plugged, or abandoned, the commission will consider requiring corrective action to prevent movement of fluid into fresh water strata.

(A) In determining the need for corrective action, the commission will consider the following factors: nature and volume of injected fluid; nature of native fluids; potentially affected population; geology; hydrology; history of the injection operation; completion and plugging records; abandonment procedures in effect at the time a well was abandoned; and hydraulic connections with fresh water.

(B) For an existing brine mining injection well requiring corrective action, any permit issued will include a compliance schedule leading to compliance with corrective action requirements. The compliance schedule will require compliance as soon as possible and in no case later than one year after the effective date of the permit. The permit will require the operator to submit a written compliance report within 30 days after all required corrective action has been taken.

(C) For a new brine mining injection well, the operator may not begin injection operations until all required corrective action has been taken.

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

(1) Modification, or revocation and reissuance. The

following are causes for modification, or revocation and reissuance:

(A) material and substantial alterations or additions to the facility occurred after permit issuance and justify permit conditions that are different or absent in the existing permit;

(B) the commission receives new information;

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

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

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

(F) a transfer of the permit is proposed.

(2) Minor modifications. With the operator's consent, the director may make minor modifications to a permit administratively, without following the procedures of subsection (i) of this section. Minor modifications may only:

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

(B) require more frequent monitoring or reporting;

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

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

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

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

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

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

(D) the commission determines that the permitted injection endangers human health or the environment, or that pollution of fresh water is occurring or is likely to occur as a result of the permitted injection; or

(E) fluids are escaping from the permitted injection zone.

(i) Permitting procedures.

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

(2) Permit denial. If the director administratively denies a permit application, a notice of administrative denial will be mailed to the applicant. The applicant will have a right to a hearing on request. If the applicant requests a hearing, the notice of administrative denial will be subject to the same procedures as a draft permit prepared under paragraph (3) of this subsection.

(3) Draft permits.

(A) A draft permit will be prepared when the director tentatively decides:

(i) to issue a permit;

(ii) to modify, or revoke and reissue, a permit; or

(iii) to terminate a permit, in which case the director will prepare a notice of intent to terminate, which is a type of draft permit.

(B) A draft permit will contain all proposed permit conditions.

(4) Fact sheets. The director will prepare a fact sheet to accompany every draft permit that the director finds is the subject of widespread public interest or raises important issues. The fact sheet will briefly set forth the principal facts and the significant factual, legal, methodological, and policy questions considered in preparing the draft permit.

The fact sheet will include information satisfying the requirements of 40 Code of Federal Regulations §124.8(b).

(5) Notice.

(A) The commission will give notice when a draft permit is prepared under paragraph (3) of this subsection, and when a hearing is scheduled under paragraph (7) of this subsection.

(B) Notice will be given by the methods specified in this subparagraph.

(i) A copy of the notice will be mailed to the following persons:

(I) any agency that the commission knows has issued or is required to issue a permit for the same facility under any federal or state environmental program;

(II) the United States Environmental Protection Agency;

(III) persons on a mailing list developed according to 40 Code of Federal Regulations §124.10(c)(1)(viii);

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

(V) the operator; and

(VI) any oil and gas operators or surface owners required to be listed in the application under subsection (d)(4)(F) and (G) of this section. If, pursuant to subsection (d)(4)(G), the director waived the requirement to list certain surface owners in the application, the applicant shall notify such persons by publishing the notice. The notice shall be published by the applicant once each week for two consecutive weeks in a newspaper of general circulation for the county where the facility is located. The applicant shall file proof of publication with the commission in Austin.

(ii) The notice shall be published by the applicant at least once in a newspaper of general circulation for the county where the facility is located. The applicant shall file proof of publication with the commission in Austin.

(C) Notices will include information satisfying the requirements of 40 Code of Federal Regulations §124.10(d) and the Texas Government Code, Chapter 2001.

(D) A copy of any draft permit, fact sheet, and application will be mailed to the persons notified under subparagraph (B)(i)(I) and (II) of this paragraph, and to any other person upon request. The applicant will be mailed a copy of any draft permit and fact sheet.

(E) The Texas Commission on Environmental Quality, the Texas Water Development Board, the Texas Department of Health, the Texas Parks and Wildlife Department, the United States Fish and Wildlife Service, other state and federal agencies with jurisdiction over fish, shellfish, and wildlife resources, the Advisory Council on Historic Preservation, state historic preservation officers, and other appropriate government authorities will be given opportunity to receive copies of notices, applications, draft permits, and fact sheets.

(6) Comments and requests for hearing. Notice of a draft permit will allow at least 30 days for public comment. During the public comment period, any interested person may submit written comments on the draft permit and may request a hearing if one has not already been scheduled.

(7) Hearings on draft permits.

(A) A hearing will be held:

(i) when the director finds, on the basis of requests, a significant degree of public interest in a draft permit;

(ii) when an applicant or an affected person requests a hearing on a draft permit; or

(iii) when an operator requests a hearing on a draft permit prepared when the director tentatively decides to modify, revoke and reissue, or terminate a permit.

(B) The commission may hold a hearing at its discretion, for instance, when a hearing might clarify one or more issues involved in the permit decision.

(C) Notice of a hearing will be given at least 30 days before the hearing. The public comment period under paragraph (6) of this subsection will automatically be extended to the close of any hearing under this paragraph.

(8) Administrative approval. After the close of the public comment period, the director may issue, modify, revoke and reissue, or terminate a permit administratively if no hearing is required under paragraph (7) of this subsection.

(9) Response to comments. When a final permit is issued, the commission will respond in writing to comments received during the public comment period. The response will be made available to the public and will:

(A) specify which provisions, if any, of the draft permit have been changed in the final permit, and the reasons for the changes; and

(B) briefly describe and respond to all significant comments on the draft permit raised during the public comment period, or during any hearing on the draft permit.

(j) Commission review of administrative actions. Administrative actions performed by the director or

commission staff pursuant to this section are subject to review by the commissioners.

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

(l) Effective date. This section becomes effective upon approval of the commission's Class III Underground Injection Control (UIC) Program for brine mining injection wells by the United States Environmental Protection Agency under the Safe Drinking Act, §1422 (42 United States Code §300h-1).

Source Note: The provisions of this §3.81 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.83 Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain commission certification of a wellbore as a two-year inactive well or three-year inactive well in order to qualify for the tax exemptions provided for in the Tax Code, §§201.053, 202.052, and 202.056.

(b) Definitions.

(1) Two-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the two years prior to the date of certification by the Commission under this section.

(2) Three-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the three years prior to the date of certification by the commission under this section.

(3) Eligible well--Wells eligible under this section include those that:

(A) were previous producing or injection wells that have not been plugged or abandoned; or

(B) have been plugged and abandoned; or

(C) are active injection wells.

(4) Well--A wellbore with single or multiple completions.

(c) Certification. The commission or its delegate may certify a well as a two-year inactive well or a three-year inactive well. If the commission or its delegate declines to certify a well administratively, the operator affected by this action may request a hearing.

(d) Revocation of Certification. Certification of a two-year inactive well or a three-year inactive well may be revoked by the commission for cause which includes, but is not limited to, receipt of information by the commission that a certified well produced hydrocarbons in more than one calendar month in the applicable two or three years prior to certification, or if production from other wells is credited to the two-year inactive well or the three-year inactive well, or if a certified well is reported to the commission to be capable of production but is not capable of production. The Comptroller of Public Accounts will be notified of any revocation.

(e) Certified Wells.

(1) Three-year inactive wells. The commission may not certify a three-year inactive well under this section after February 29, 1996. Prior to applying to the Comptroller of Public Accounts for the tax incentives listed in subsection (a) of this section, the operator of a three-year inactive certified well shall file with the commission a test report showing productive capability for the well. Production is presumed to begin on this well test date. The certification remains with the well in the event of a change of operator or ownership.

(2) Two-year inactive wells. The commission may not designate a two-year inactive well under this section after February 28, 2010. An application for two-year inactive well certification shall be made during the period of September 1, 1997, through August 31, 2009, to qualify for the tax exemption. Certification will be issued upon the filing of a test report showing the well's capability and an approval of application for certification. Production is presumed to begin on the well test date as reported on the appropriate report. The certification shall remain with the well in the event of a change of operator or ownership.

Source Note: The provisions of this §3.83 adopted to be effective November 23, 1993, 18 TexReg 8195; amended to be effective January 10, 1996, 20 TexReg 11119; amended to be effective July 21, 1998, 23 TexReg 7363; amended to be effective September 10, 2001, 26 TexReg 6869.

§3.84 Gas Shortage Emergency Response

(a) The purpose of this section is to provide a means for a producer or purchaser to increase production and takes from wells in a field in response to an increase in demand caused by unforeseen events. This section outlines the commission's mechanisms for both determining that a gas shortage emergency exists, and responding to a gas shortage emergency.

(b) The commission may, after notice and hearing, determine that a gas shortage emergency exists or has existed. The commission may also determine the duration of the emergency at such hearing. The commission shall

issue notice when it has determined that a gas shortage emergency exists, or has existed, and when it determines the gas shortage emergency has ended or will end. In determining whether a gas shortage emergency exists or has existed, the commission shall consider any relevant information, including, but not limited to, the following:

(1) notification from gas storage facilities that they are attaining maximum gas withdrawal rates;

(2) notification from a gas utility, distributor, transporter, producer or purchaser that gas shortages have occurred or are anticipated; and

(3) weather data.

(c) Upon the commission's finding that a gas shortage emergency exists, or has existed, producers or purchasers shall be authorized to meet the increased demand for the duration of the gas shortage emergency as determined by the commission regardless of a well's assigned allowable or allowable status.

(d) If inequities occur as a result of production authorized by subsection (c) of this section, an adjustment shall be made at the hearing in which production reported for the month of the gas shortage emergency is considered in setting future allowables. Such adjustment shall include the assignment of additional allowable to adequately protect correlative rights. The commission may determine the maximum amount of the supplemental allowable by multiplying the number of days of the gas shortage emergency period by the difference between the well's capability (as defined in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable)) and the assigned allowable.

Source Note: The provisions of this §3.84 adopted to be effective September 13, 1994, 19 TexReg 6853; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.85 Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle

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

(1) Cargo manifest--One or more documents that together contain the information required by subsection (c) of this section. That part of a manifest which contains information unique to the particular transport being described (such as date and time of removal) must be part of a book, tablet, or series, wherein the documents are sequentially numbered.

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

(3) Facility--Any place used to store, process, refine, reclaim, dispose of, or treat liquid hydrocarbons.

(4) Lease--A well producing oil, gas, or oil and gas, and any group of contiguous wells producing oil, gas, or oil and gas of any number operated as a producing unit.

(5) Liquid hydrocarbons--Unrefined oil or condensate, and refined oil or condensate to be blended with unrefined liquid hydrocarbons.

(6) Oil tanker vehicle--A motor vehicle licensed for highway use on a public highway or used on a public highway:

(A) that is equipped with, carrying, pulling, or otherwise transporting an assembly, compartment, tank, or other container that is used for transporting, hauling, or delivering liquids; and

(B) that is being used to transport liquid hydrocarbons on a public highway.

(7) Public highway--A way or place of whatever nature open to the use of the public as a matter of right for the purpose of vehicular travel, even if the way or place is temporarily closed for the purpose of construction, maintenance, or repair.

(8) Transporter--Each gatherer, storer, or other handler of liquid hydrocarbons who moves or transports those liquid hydrocarbons by truck or other motor vehicle, provided however, that the provisions of this rule do not apply to:

(A) common carriers as defined in the Natural Resources Code, Chapter 111; or

(B) the movement of salt water, brine, sludge, drilling mud, or other liquid or semiliquid material if the commission has authorized the entity to move such material and such material contains less than 7.0% liquid hydrocarbon, by volume, or if not authorized by the commission, the movement is not for hire and the material moved does not contain more than 7.0% liquid hydrocarbons by volume.

(b) A cargo manifest must be carried in each oil tanker vehicle transporting liquid hydrocarbons on a public highway in this state and must be presented on request for inspection as provided by subsection (f) of this section.

(c) For each load of liquid hydrocarbons loaded onto and transported by an oil tanker vehicle, the cargo manifest must include:

(1) an identification of the lease or facility from which the liquid hydrocarbons were removed, which must include:

(A) the lease or facility name; and

(B) the name of the operator of the lease or facility;

(2) the total quantity of liquid hydrocarbons removed from the lease or facility and loaded onto the oil tanker

vehicle; provided that for purposes of indicating quantity on the copy of the manifest left with the lease operator, top and bottom gauges will suffice. On the other copies, an estimate in barrels must be included;

(3) the date and hour when the liquid hydrocarbons were removed from the lease or facility and loaded onto the oil tanker vehicle;

(4) the identity of the transporter which must include;

(A) the company or individual transporter's name and address;

(B) the oil tanker vehicle driver's name; and

(C) a unique number for the oil tanker vehicle that for a truck tractor and semitrailer type oil tanker vehicle must include unique vehicle numbers for both truck tractor and semitrailer; and

(5) the intended point of destination for the liquid hydrocarbons, including the name of the receiving facility.

(d) Copy of manifest to be left at the lease.

(1) A copy of the cargo manifest must be left at the lease or facility from which the liquid hydrocarbons were removed or delivered to the lease or facility operator, his agent, or his representative.

(2) The requirements of this section may be met by leaving a separate document at the lease or facility from which the liquid hydrocarbons were removed or by delivering to the lease or facility operator a separate document that includes information required under subsection (c)(1)-(3) and (4)(A) and (B) this section.

(3) If more than one load of liquid hydrocarbons is removed from a single tank or other container of liquid hydrocarbons within a period of 24 consecutive hours, subsection (c)(2) and (3) of this section may be met for purposes of this section by a separate document that includes:

(A) the total quantity of liquid hydrocarbons removed;

(B) the date and hour the first load was removed; and

(C) the date and hour the last load was removed.

(4) If the operator of a facility requires that a transporter leave at the facility or deliver to the operator a document other than the transporter's cargo manifest, a transporter may meet the requirements of this section by leaving those specified documents at an agreed location or delivering the document to the operator.

(e) After the delivery of all liquid hydrocarbons in an oil tanker vehicle is completed, the cargo manifest must be maintained in the records of the transporter for a period of not less than two years from the date the liquid hydrocarbons are removed from the oil tanker vehicle.

(f) Upon request from a commission agent or other law enforcement official the transporter must produce the cargo manifest for inspection immediately, whether it is on an oil tanker vehicle or in the records of the transporter. Copies of cargo manifests must be filed with the commission, upon request from the commission.

(g) Companies or individuals who do not have organization reports (Form P-5) on file with the Railroad Commission, as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirement (commonly referred to as Statewide Rule 1)), may not issue cargo manifests.

(h) Every truck or other vehicle covered by this section shall bear on both sides thereof the name of the company or individual responsible for such transportation, the number of the vehicle, and the number of the certificate or permit authorizing the service. In the case of vehicles not for hire, this number shall be the company's organizational report (P-5) number. The identifying signs shall be printed in letters not less than two inches in height, in sharp color contrast to the background, and shall be plainly legible for a distance of at least 50 feet.

Source Note: The provisions of this §3.85 adopted to be effective August 25, 2003, 28 TexReg 6816.

§3.86 Horizontal Drainhole Wells

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

(1) Correlative interval--The depth interval designated by the field rules or by new field designation on Form P-7 (New Field Designation).

(2) First take point--The take point in a horizontal drainhole well nearest to the point where the drainhole penetrates the top of the correlative interval. The first take point may be at a location different from the penetration point.

(3) Horizontal drainhole--That portion of the wellbore drilled in the correlative interval, between the penetration point and the terminus.

(4) Horizontal drainhole displacement--The calculated horizontal displacement of the horizontal drainhole from the first take point to the last take point.

(5) Horizontal drainhole well--Any well that is developed with one or more horizontal drainholes having a horizontal drainhole displacement of at least 100 feet.

(6) Last take point--The take point in a horizontal drainhole well nearest the terminus. The last take point

may be at a location different from the terminus.

(7) Nonperforation zone (NPZ)--A portion of a horizontal drainhole well within the field between the first take point and the last take point that the operator has intentionally designated as containing no take points pursuant to the spacing requirements in §3.37 of this title (relating to Statewide Spacing Rule).

(8) Penetration point--The point where the drainhole penetrates the top of the correlative interval.

(9) Record well--The single horizontal drainhole within a stacked lateral well designated by the operator as the record well for reporting purposes.

(10) Stacked lateral well--A horizontal drainhole well in which the following conditions are met:

(A) there are two or more horizontal drainhole wells on the same lease, pooled unit, or unitized tract at different depths within the correlative interval for the field;

(B) the horizontal drainholes are drilled from different surface locations;

(C) all take points of a stacked lateral well's horizontal drainholes are within a rectangular area the width of which is 660 feet, and the length of which is 1.2 times the distance between the first and last take points of the record well;

(D) all horizontal drainholes are tested independently and have the same classification (i.e., gas or oil). Only horizontal drainholes of the same classification are eligible to be designated as a stacked lateral well; and

(E) there is only one operator for the stacked lateral well.

(11) Take point in a horizontal drainhole well--Any point along a horizontal drainhole where oil and/or gas can be produced from the correlative interval.

(12) Terminus--The farthest point required to be surveyed along the horizontal drainhole from the penetration point and within the correlative interval.

(13) Unconventional fracture treated (UFT) field--A field designated by the Commission under subsection (i) of this section for which horizontal well development and hydraulic fracture treatment (as defined in §3.29(a)(15) and (16) of this title (relating to Hydraulic Fracturing Chemical Disclosure Requirements)) must be used in order to recover resources from all or a part of the field and which may include the drilling of vertical wells along with the drilling of horizontal wells.

(b) Drainhole spacing.

(1) No take point on a horizontal drainhole shall be located nearer than 1,200 feet (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any take point along any other horizontal drainhole in another well, or to any other well completed or permitted in the same field on the same lease, pooled unit, or unitized tract.

(2) No take point on a horizontal drainhole shall be located nearer than 467 feet, or other lease-line spacing requirement under applicable rules for the field, from any property line, lease line, or subdivision line.

(3) All wells developed with horizontal drainholes shall otherwise comply with §3.37 of this title (relating to Statewide Spacing Rule), or other applicable spacing rules.

(4) If the drilling permit application indicates that there will be one or more NPZs, then the as-drilled plat filed after completion of the well shall be certified by a person with knowledge of the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data. In addition to the information required under subsection (f) of this section, the certified as-drilled plat shall include:

(A) the as-drilled track of the wellbore;

(B) the location of each take point on the wellbore;

(C) the boundaries of any wholly or partially unleased tracts within the distance permitted under §3.37 of this title or applicable special field rules of the wellbore; and

(D) notations of the shortest distance from each wholly or partially unleased tract within the distance permitted under §3.37 of this title or applicable special field rules of the wellbore to the nearest take point on the wellbore.

(5) To comply with the spacing requirements set forth in paragraph (3) of this subsection, the take-points along the as-drilled location of a properly permitted horizontal drainhole shall fall within a rectangle established as follows:

(A) two sides of the rectangle are parallel to the permitted drainhole and 50 feet or 10% of the minimum distance to any property line, lease line or subdivision line, whichever is greater, on either side of the drainhole; and

(B) the other two sides of the rectangle are perpendicular to the sides described in subparagraph (A) of this paragraph, with one of those sides passing through the permitted first take point and the other side passing through the permitted last take point.

(6) Prior to perforating the wellbore within an approved NPZ, the operator must amend the permit to authorize perforations within the originally-approved NPZ.

(c) Well densities. All wells developed with horizontal drainholes shall comply with §3.38 of this title (relating to

Well Densities) or other applicable density rules.

(d) Proration and drilling units.

(1) Acreage may be assigned to each horizontal drainhole well for the purpose of allocating allowable oil or gas production up to the amount specified by applicable rules for a proration unit for a vertical well plus the additional acreage assignment as provided in this paragraph.

Additional Acreage Assignment
For Fields with a Density Rule of 40 Acres or Less

Horizontal Drainhole Displacement, ft	Additional Acreage Allowed, acres
100 to 585	20
586 to 1,170	40
1,171 to 1,755	60
1,756 to 2,340	80
2,341 to 2,925	100
2,926 to 3,510	120
etc. - 585 ft increments	etc. - 20 acre increments

Additional Acreage Assignment
For Fields with a Density Rule Greater Than 40 Acres

Horizontal Drainhole Displacement, ft	Additional Acreage Allowed, acres
150 to 827	40
828 to 1,654	80
1,655 to 2,481	120
2,482 to 3,308	160
3,309 to 4,135	200
4,136 to 4,962	240
etc. - 827 ft increments	etc. - 40 acre increments

(2) Assignment of acreage to proration and drilling units for horizontal drainhole wells shall comply with §3.40 of this title (relating to Assignment of Acreage to Pooled Development and Proration Units).

(3) All proration and drilling units shall consist of continuous and contiguous acreage and proration units shall consist of acreage that can be reasonably considered to be productive of oil or gas.

(4) The maximum daily allowable assigned to a horizontal well shall comply with the table in subsection (d)(1) of this section and the maximum daily allowable specified by paragraph (5) of this subsection, unless special field rules specify different requirements for acreage or maximum daily allowable.

(5) The maximum daily allowable for a horizontal drainhole well in a designated UFT field shall be 100 barrels of oil for each acre that is assigned to an oil well for allowable purposes, or 600 Mcf of gas for each acre that is assigned to a gas well for allowable purposes. This paragraph does not affect suspension of the allocation formula under §3.31(j) of this title (relating to Gas Reservoirs and Gas Well Allowable). The maximum daily allowable for a horizontal drainhole well in a field that has not been designated as a UFT field shall be determined by multiplying the applicable allowable for a vertical well in the field with a proration unit containing the maximum acreage authorized by the applicable rules for the field,

exclusive of tolerance acreage, by a fraction:

(A) the numerator of which is the acreage assigned to the horizontal drainhole well for proration purposes; and

(B) the denominator of which is the maximum acreage authorized by the applicable field rules for proration purposes, exclusive of tolerance acreage. The daily oil allowable shall be adjusted in accordance with §3.49(a) of this title (relating to Gas-Oil Ratio), when applicable.

(6) All points on the horizontal drainhole from the first take point to the terminus shall be within the proration and drilling unit. If the penetration point is located on an offsite tract, the conditions prescribed in subsection (g) of this section shall be met before the drilling permit application is submitted to the Commission.

(e) Multiple drainholes allowed.

(1) A single well may be developed with more than one horizontal drainhole originating from a single vertical wellbore.

(2) A horizontal drainhole well developed with more than one horizontal drainhole shall be treated as a single well.

(3) The horizontal drainhole displacement used for calculating additional acreage assignment for a well completed with multiple horizontal drainholes shall be the horizontal drainhole displacement of the longest horizontal drainhole plus the projection of any other horizontal drainhole on a line that extends in a 180 degree direction from the longest horizontal drainhole.

(f) Stacked lateral wells.

(1) For oil and gas wells, stacked lateral wells within the correlative interval for the field may be considered a single well for density and allowable purposes, at an operator's discretion. If an operator chooses to designate horizontal drainholes as a stacked lateral well, the operator shall designate:

(A) one horizontal drainhole within the stacked lateral well as the record well. An operator may change the record well designation to another wellbore by filing amended drilling permit applications and completion reports for the previous and the new record well; and

(B) all points, from the first take point to the last take point, of the record well for a stacked lateral well are within the proration and drilling unit designated for that well. Notwithstanding paragraph (4) of this subsection, all points from the first take point to the last take point of any other horizontal drainhole comprising the stacked lateral well are not required to be within the proration and drilling unit designated for the record well so long as they otherwise comply with the requirements of this section and any applicable lease line spacing rules.

(2) For the purpose of assigning additional acreage to the stacked lateral well, the horizontal drainhole displacement shall be calculated based on the distance from the first take point to the last take point in the horizontal drainhole for the record well, regardless of the horizontal drainhole displacement of other horizontal drainholes of the stacked lateral well.

(3) Each surface location of a stacked lateral well shall be permitted separately and assigned an API number. When applying for a drilling permit for a stacked lateral well, the operator shall:

(A) identify each surface location of such well as a stacked lateral well on the Form W-1 drilling permit application;

(B) identify on the plat any other existing, or applied for, horizontal drainholes comprising the stacked lateral well being permitted; and

(C) depict on the plat a rectangle described in subsection (a)(10)(C) of this section indicating the lateral boundaries of the stacked lateral well.

(4) Each horizontal drainhole of a stacked lateral well shall comply with: the applicable minimum spacing distance under §3.37 of this title or any applicable special field rules for any lease, pooled unit or property line; and the applicable minimum between well spacing distance under §3.37 of this title or any applicable special field rules for any different well, including all horizontal drainholes of any other stacked lateral well, on the same lease or pooled unit in the field. An operator may seek an exception to §3.37 or §3.38 of this title for stacked lateral wells in accordance with the Commission's rules in this chapter or any applicable special field rule. There are no maximum or minimum distance limitations between horizontal drainholes of a stacked lateral well in a vertical direction.

(5) An operator shall file separate completion forms for each surface location of the stacked lateral well. An operator shall also file a certified plat showing the as-drilled location for each surface location of a stacked lateral well. The certified as-drilled plat shall:

(A) show each horizontal drainhole from each surface location; and

(B) depict on the plat a rectangle described in subsection (a)(10)(C) of this section indicating the lateral boundaries of the stacked lateral well.

(6) In addition to the record well, each surface location of a stacked lateral well shall be listed on the proration schedule, but no allowable shall be assigned for an individual surface location. Each surface location of a stacked lateral well shall be required to have a separate well status report (Form G-10 or Form W-10, as applicable) and the sum of all horizontal drainhole test rates shall be reported as the test rate for the record well.

(7) An operator shall report all production from horizontal drainholes included as a stacked lateral well on the production report that includes the record well. Production reported for a record well shall equal the total production from all of the horizontal drainholes comprising the stacked lateral well. An operator shall measure the production from each surface location of a stacked lateral well. An operator shall measure the full well stream with the measurement adjusted for the allocation of condensate based on the gas to liquid ratio established by the most recent Form G-10 test rate for that surface location. The gas and condensate production shall be identified by individual API number, and recorded and reported on the "Supplementary Attachment to Form PR".

(8) If the field is designated as absolute open flow (AOF) pursuant to §3.31(j) of this title and that designation is removed, the Commission shall assign a single gas allowable to each record well classified as a gas well. The assigned allowable may be produced from any one, all, or a combination of the horizontal drainholes that constitute the stacked lateral well.

(9) An operator shall file Form W-3A, Notice of Intention to Plug and Abandon, and Form W-3, Well Plugging Report, for each horizontal drainhole within the stacked lateral well as required by §3.14 of this title (relating to Plugging).

(10) In order to maintain a single operator of record for a stacked lateral well, a certificate of compliance changing the designation of an operator for a horizontal drainhole in a stacked lateral well pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) may only be approved if certificates of compliance designating the same operator have been filed for all horizontal drainholes within the stacked lateral well.

(11) An operator may remove a horizontal drainhole from a designated stacked lateral well by filing an amended drilling permit application and a completion report. If the horizontal drainhole being removed is the record well for the stacked lateral and there are still multiple horizontal drainholes remaining within the designated stacked lateral well, then the operator shall designate a new record well for the stacked lateral well prior to removing the existing record well from the designated stacked lateral well.

(g) Drilling applications and required reports.

(1) Application. Any intent to develop a new or existing well with horizontal drainholes must be indicated on the application to drill. An application for a permit to drill a horizontal drainhole shall include the fees required by §3.78 of this title (relating to Fees and Financial Security Requirements), and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge. If the penetration point on the proposed horizontal drainhole is located on an offsite tract, the following conditions shall be met prior to submission of the application to drill:

(A) The applicant shall give written notice by certified mail, return receipt requested, to all mineral owners of any offsite tracts through which the proposed wellbore path traverses from the point of penetration. The notice shall identify the proposed well, include a plat clearly depicting the projected path of the entire wellbore, and allow the party notified not less than 21 days to object to the proposed offsite tract penetration. Notice of offsite tract penetration is not required if:

(i) written waivers of objection are received by the applicant from all mineral owners of any offsite tracts and the waivers are attached to the drilling permit application; or

(ii) the applicant is the only mineral owner of any offsite tracts.

(B) For purposes of this subsection, the mineral owners of any offsite tracts through which the proposed wellbore path traverses from the point of penetration include:

(i) the designated operator;

(ii) all lessees of record for any offsite tracts which have no designated operator; and

(iii) all owners of unleased mineral interests where there is no designated operator or lessee.

(C) In the event the applicant is unable after due diligence to locate the whereabouts of any person to whom notice is required by this subsection, the applicant shall publish notice of this application pursuant to Chapter 1 of this title (relating to Practice and Procedure).

(D) If any mineral owner of an offsite tract objects to the location of the penetration point, the applicant may request a hearing to demonstrate the necessity of the location of the penetration point of the well to prevent waste or to protect correlative rights.

(E) If any person specified in subparagraph (B) of this paragraph did not receive notice as required in subparagraph (A) of this paragraph, that person may request a hearing. If the Commission determines at a hearing that the applicant did not provide the notice as required by subparagraph (A) of this paragraph, the Commission may cancel the permit.

(F) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the parties entitled to notice under this section, upon request, within 15 days of the applicant's receipt of a request.

(2) Drilling unit plat. The application to drill a horizontal drainhole shall be accompanied by a plat as required by §3.5(h) of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back).

(A) For fields that require a proration unit plat, in addition to the plat requirements provided for in §3.5(h) of this title, the plat shall include the lease, pooled unit or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract.

(B) An amended drilling permit application and plat shall be filed after completion of the horizontal drainhole well if the Commission determines that the drainhole as drilled is not reasonable with respect to the drainhole represented on the plat filed with the drilling permit application. A horizontal drainhole, as drilled, shall be considered reasonable with respect to the drainhole represented on the plat filed with the drilling permit application if the take points on the as-drilled plat comply with subsection (b)(4) and (5) of this section and with any applicable lease line spacing rules.

(3) Directional survey. A directional survey from the surface to the farthest point drilled on the horizontal drainhole shall be required for all horizontal drainholes. The directional survey and accompanying reports shall be conducted and filed in accordance with §3.11 and §3.12 of this title (relating to Inclination and Directional Surveys Required, and Directional Survey Company Report, respectively). No allowable shall be assigned to any horizontal drainhole well until an acceptable directional survey and survey plat has been filed with the Commission.

(4) Proration unit plat. The required proration unit plat must depict the lease, pooled unit, or unitized tract, showing the acreage assigned to the proration unit for the horizontal drainhole well, the acreage assigned to the proration units for all wells on the lease, pooled unit, or unitized tact, and the path, penetration point, take points, and terminus of all drainholes. No allowable shall be assigned to any horizontal drainhole well until an acceptable proration unit plat has been filed with the Commission. Proration unit plats are not required for wells in a designated UFT field. However, an operator of a well in a designated UFT field may file a proration unit plat along with Form P-16. Designated UFT fields have no maximum diagonal limit.

(5) As-drilled plat. An as-drilled plat is required for each horizontal drainhole well. The as-drilled plat for each horizontal drainhole well shall show the surface location, actual wellbore path, penetration point, terminus, and first and last take points of the horizontal drainhole. If the drilling permit for the horizontal drainhole well is approved with one or more NPZs, the as-drilled plat shall show the nearest take point on either side of each NPZ.

(6) Plat requirements. All plats required by this section shall be prepared using blue or black ink and shall include a certification by a professional land surveyor registered in accordance with Texas Occupations Code, Chapter 1071, relating to Land Surveyors, or by a registered professional engineer registered in accordance with Texas Occupations Code, Chapter 1001, relating to Professional Engineers.

(h) Exceptions and procedure for obtaining exceptions.

(1) The Commission may grant exceptions to this section in order to prevent waste, prevent confiscation, or to protect correlative rights.

(2) If a permit to drill a horizontal drainhole requires an exception to this section, the notice and opportunity for hearing procedures for obtaining exceptions to the density provisions prescribed in §3.38 of this title shall be followed as set forth in §3.38(h) of this title.

(3) For notice purposes, the Commission presumes that for each adjacent tract and each tract nearer to any point along the proposed or existing horizontal drainhole than the prescribed minimum lease-line spacing distance, affected persons include:

(A) the designated operator;

(B) all lessees of record for tracts that have no designated operator; and

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

(i) UFT field designation criteria, application and approval procedures.

(1) Criteria for UFT field designation.

(A) Administrative UFT field designation. To be designated administratively as a UFT field, a field shall have the following characteristics:

(i) the *in situ* permeability of at least one distinct producible interval within the field is 0.1 millidarcies or less prior to hydraulic fracture treatment, as determined by core data or other supporting data and analysis; and

(ii) as to producing wells for which the Commission issued the initial drilling permit on or after February 1, 2012, that have been completed in the field, either:

(I) there are at least five such wells of which at least 65% were drilled horizontally and completed using hydraulic fracture treatment; or

(II) there are at least twenty-five such wells drilled horizontally and completed using hydraulic fracture treatment.

(B) Alternative UFT field designation obtained through evidentiary hearing. If an applicant demonstrates in a hearing that reservoir characteristics exist other than the characteristics specified in subparagraph (A) of this paragraph such that horizontal drilling and hydraulic fracture treatment must be used in order to recover the resources from all or a part of the field and that UFT field designation will promote orderly development of the field, the hearings examiner may recommend to the Commission

that the field be designated as a UFT field.

(2) Procedures for UFT field designation.

(A) Commission motion to designate a UFT field. The Commission may on its own motion propose that a field be designated as a UFT field upon written notice of the motion to all operators in the field.

(i) If no written objection is filed within 21 days after the date the notice is issued, Commission staff may present a recommendation to the Commission regarding designation of the field as a UFT field.

(ii) If the Commission receives a timely filed written objection, the Commission shall notify the operators in the field that an objection was received and allow any operator in the field 21 days to request a hearing. Pursuant to paragraph (1)(B) of this subsection, the operator requesting the hearing shall bear the burden of proof at the hearing. If no request to set the matter for hearing is received from an operator in the field, the Commission may either dismiss the matter or set the matter for hearing on its own motion. If the matter is set for hearing on the Commission's motion, the proponents of UFT field designation shall bear the burden of proof.

(B) Operator application for UFT designation.

(i) An operator may propose that a field be designated as a UFT field by submitting an application to the Commission that includes an affirmative statement that the field qualifies for designation as a UFT field and providing core data or other supporting data and analysis in support of that affirmative statement.

(ii) If, on review of the completed application, Commission staff determines that the field meets the criteria in paragraph (1)(A) of this subsection, Commission staff shall notify all operators in the field that a UFT field designation order may be presented to the Commission for approval not less than 21 days after the date the notice is issued unless the Commission receives a written objection. If the applicant provides written waivers of objection from all operators in the field, then notice to the operators in the field shall not be required.

(iii) If the Commission receives a timely filed written objection to the notice of the proposal to designate the field as a UFT field, or if Commission staff determines that the field does not qualify for designation as a UFT field, then the applicant for UFT field designation may request that the application be set for hearing.

(iv) If the applicant requests a hearing, the Commission shall send a notice of hearing to all operators in the field proposed for designation as a UFT field at least 15 days in advance of the hearing.

(v) Following a hearing on the request, the hearings examiner may present a recommendation to the Commission regarding the request to designate the field as a UFT field.

(j) Effect of special field rules for UFT fields.

(1) Special field rules for a UFT field shall prevail over all conflicting provisions of this chapter.

(2) The Commission may on its own motion or on the motion of an operator in a field call a hearing to review the current special field rules applicable in a field that is designated or proposed to be designated as a UFT field and request amendment or rescission of any portion of the current field rules, in conjunction with such designation, so that the field is regulated with the appropriate combination of special field rules and the rules in this chapter to effectively and efficiently protect correlative rights and/or prevent waste.

(3) The following provisions shall apply with respect to specific amendments to the special field rules for a UFT field.

(A) A special field rule amendment hearing is not required for the following amendments:

(i) reduction of the standard and/or optional density to one-half of the existing standard and/or optional density;

(ii) deletion of the between-well spacing rule; or

(iii) replacement of the allowable provided by special field rules with the allowable provided by §3.31 of this title, §3.45 of this title (relating to Oil Allowables), and subsection (d)(4) and (5) of this section.

(B) To request one or more of the amendments listed in subparagraph (A) of this paragraph, the operator shall submit to the Commission a request for amendment and engineering and/or geological data to support the requested amendments. For each exhibit submitted, the operator shall include a written explanation showing that the requested amendment will result in the protection of correlative rights and/or the prevention of waste.

(C) Upon receipt of a request for amendment, the Commission shall provide notice of the request to all operators in the field. If no written objection is filed within 21 days after the date the notice is issued, Commission staff may present a recommendation to the Commission regarding the requested amendment. If the Commission receives a timely filed written objection, the applicant may request a hearing to establish through the submission of competent evidence that the requested amendment is necessary for continued development of a designated UFT field, and will result in the protection of correlative rights and/or prevention of waste.

(k) Exceptions to §3.38 for a well in a UFT field. To request an exception to §3.38 of this title for a well in a UFT field:

(1) The operator shall submit to the Commission a written request for an exception to §3.38 of this title. The

operator shall clearly state on the drilling permit application whether the density exception is sought under this subsection or through the provisions of §3.38 of this title.

(2) The Commission shall send written notice of the request for an exception to §3.38 of this title filed under this subsection to any designated operators, lessees of record for tracts that have no designated operator, and all owners of unleased mineral interests:

(A) within 600 feet from the location of a vertical well completed within the UFT field; or

(B) within 600 feet from any take point on a horizontal well within the UFT field correlative interval.

(3) Persons who have received notice pursuant to paragraph (2) of this subsection shall have 21 days from the date of issuance of the notice to file a written objection with the Commission.

(4) If no timely filed written objection is received by the Commission, the applicant provides written waivers from all persons entitled to notice under paragraph (2) of this subsection, or there are no persons entitled to notice, then the application may be approved administratively without the requirement of filing supporting data.

(5) If a timely filed written objection is received by the Commission, the applicant may request a hearing, at which the applicant shall show that the proposed exception to §3.38 of this title is necessary to effectively drain an area of the UFT field that will not be effectively drained by existing wells or to prevent waste or confiscation. Notice of a hearing for a protested exception application under §3.38 of this title for a well in a UFT field will be provided to those persons entitled to notice of such an application as specified in paragraph (2) of this subsection.

(6) Permits granted pursuant to paragraphs (1) - (5) of this subsection shall be issued as exceptions to §3.38 of this title.

(7) Nothing in this subsection prevents an operator from electing to apply for and obtain a density exception under the provisions of §3.38 of this title rather than the provisions of paragraphs (1) - (6) of this subsection.

(l) Tubing requirements for completions in UFT fields. An operator of a flowing oil well in a UFT field may obtain a six-month exception to the requirement in §3.13(b)(4)(A) of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements) that flowing oil wells shall be produced through tubing. The exception may be granted administratively. A revised completion report shall be filed once the oil well has been equipped with the required tubing string to reflect the actual completion configuration.

(1) For good cause shown, including a showing that the well is flowing at a pressure in excess of 300 psig surface wellhead flowing pressure, an operator may obtain from the District Director one or more extensions to the six month exception. Each extension shall be no more than six months in duration. If the request for an extension is denied, the operator may request a hearing. If a hearing is requested, the exception shall remain in effect pending final Commission action on the request for an extension.

(2) This subsection applies to new drills, reworks, recompletions, or new fracture stimulation treatments for any flowing oil well in the field.

Source Note: The provisions of this §3.86 adopted to be effective June 1, 1990, 15 TexReg 2635; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective February 1, 2016, 41 TexReg 785.

§3.91 Cleanup of Soil Contaminated by a Crude Oil Spill

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

(1) Free oil--The crude oil that has not been absorbed by the soil and is accessible for removal.

(2) Sensitive areas--These areas are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. Factors that are characteristic of sensitive areas include the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, streams, dry or flowing creeks, irrigation canals, stock tanks, and wetlands; proximity to natural wildlife refuges or parks; or proximity to commercial or residential areas.

(3) Hydrocarbon condensate--The light hydrocarbon liquids produced in association with natural gas.

(b) Scope. These cleanup standards and procedures apply to the cleanup of soil in non-sensitive areas contaminated by crude oil spills from activities associated with the exploration, development, and production, including transportation, of oil or gas or geothermal resources as defined in §3.8(a)(30) of this title (relating to Water Protection). For the purposes of this section, crude oil does not include hydrocarbon condensate. These standards and procedures do not apply to hydrocarbon condensate spills, crude oil spills in sensitive areas, or crude oil spills that occurred prior to the effective date of this section. Cleanup requirements for hydrocarbon condensate spills and crude oil spills in sensitive areas will be determined on a case-by-case basis. Cleanup requirements for crude oil contamination that occurred wholly or partially prior to the effective date of this section will also be determined on a case-by-case basis. Where cleanup requirements are to be determined on a case-by-case basis, the operator must consult with the appropriate district office on proper cleanup standards and methods, reporting requirements, or other special procedures.

(c) Requirements for cleanup.

(1) Removal of free oil. To minimize the depth of oil penetration, all free oil must be removed immediately for reclamation or disposal.

(2) Delineation. Once all free oil has been removed, the area of contamination must be immediately delineated, both vertically and horizontally. For purposes of this paragraph, the area of contamination means the affected area with more than 1.0% by weight total petroleum hydrocarbons.

(3) Excavation. At a minimum, all soil containing over 1.0% by weight total petroleum hydrocarbons must be brought to the surface for disposal or remediation.

(4) Prevention of stormwater contamination. To prevent stormwater contamination, soil excavated from the spill site containing over 5.0% by weight total petroleum hydrocarbons must immediately be:

(A) mixed in place to 5.0% by weight or less total petroleum hydrocarbons; or

(B) removed to an approved disposal site; or

(C) removed to a secure interim storage location for future remediation or disposal. The secure interim storage location may be on site or off site. The storage location must be designed to prevent pollution from contaminated stormwater runoff. Placing oily soil on plastic and covering it with plastic is one acceptable means to prevent stormwater contamination; however, other methods may be used if adequate to prevent pollution from stormwater runoff.

(d) Remediation of soil.

(1) Final cleanup level. A final cleanup level of 1.0% by weight total petroleum hydrocarbons must be achieved as soon as technically feasible, but not later than one year after the spill incident. The operator may select any technically sound method that achieves the final result.

(2) Requirements for bioremediation. If on-site bioremediation or enhanced bioremediation is chosen as the remediation method, the soil to be bioremediated must be mixed with ambient or other soil to achieve a uniform mixture that is no more than 18 inches in depth and that contains no more than 5.0% by weight total petroleum hydrocarbons.

(e) Reporting requirements.

(1) Crude oil spills over five barrels. For each spill exceeding five barrels of crude oil, the responsible operator must comply with the notification and reporting requirements of §3.20 of this title (relating to Notification of Fire Breaks, Leaks, or Blow-outs) and submit a report on a Form H-8 to the appropriate district office. The following information must be included:

(A) area (square feet), maximum depth (feet), and volume (cubic yards) of soil contaminated with greater than 1.0% by weight total petroleum hydrocarbons;

(B) a signed statement that all soil containing over 1.0% by weight total petroleum hydrocarbons was brought to the surface for remediation or disposal;

(C) a signed statement that all soil containing over 5.0% by weight total petroleum hydrocarbons has been mixed in place to 5.0% by weight or less total petroleum hydrocarbons or has been removed to an approved disposal site or to a secure interim storage location;

(D) a detailed description of the disposal or remediation method used or planned to be used for cleanup of the site;

(E) the estimated date of completion of site cleanup.

(2) Crude oil spills over 25 barrels. For each spill exceeding 25 barrels of crude oil, in addition to the report required in paragraph (1) of this subsection, the operator must submit to the appropriate district office a final report upon completion of the cleanup of the site. Analyses of samples representative of the spill site must be submitted to verify that the final cleanup concentration has been achieved.

(3) Crude oil spills of five barrels or less. Spills into the soil of five barrels or less of crude oil must be remediated to these standards, but are not required to be reported to the commission. All spills of crude oil into water must be reported to the commission.

(f) Alternatives. Alternatives to the standards and procedures of this section may be approved by the commission for good cause, such as new technology, if the operator has demonstrated to the commission's satisfaction that the alternatives provide equal or greater protection of the environment. A proposed alternative must be submitted in writing and approved by the commission.

Source Note: The provisions of this §3.91 adopted to be effective November 1, 1993, 18 TexReg 6835.

§3.93 Water Quality Certification Definitions

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

(1) 401 certification--A certification issued by the commission, under the authority of the Federal Clean Water Act, §401, that a federal permit that may result in a discharge to waters of the United States is consistent with applicable state and federal water quality laws and regulations.

(2) Commission--The Railroad Commission of Texas or its designee.

(3) Department of the Army permits--Individual or general permits or letters of permission issued by the U.S. Army Corps of Engineers under the authority of the Federal Clean Water Act, §404, or the Rivers and Harbors Act of 1899, §9 and §10, United States Code, Title 33, §402 and §403.

(4) District engineer--The U.S. Army Corps of Engineers representative responsible for administering and enforcing federal laws and regulations, including processing and issuance of permits, under the jurisdiction of the U.S. Army Corps of Engineers.

(5) Federal Clean Water Act--United States Code, Title 33, Chapter 26.

(6) NPDES permit--A permit issued by the regional administrator under the authority of the Federal Clean Water Act, §402, Title 33, United States Code, §1342. NPDES permits can either be individual or general permits.

(7) Permitting agency--Any agency of the federal government to which application is made for any permit to conduct an activity that may result in any discharge into waters of the United States.

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

(9) Pollutant--Any constituent that contaminates or alters the physical, thermal, chemical, or biological quality of water so as to be harmful, detrimental, or injurious to humans, animal life, vegetation, or property or to the public health, safety, or welfare, or that impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(10) Regional administrator--The administrator of the United States Environmental Protection Agency, Region 6.

(11) Water quality standards--Texas Surface Water Quality Standards, Title 30, Texas Administrative Code, Chapter 307.

(12) Waters of the United States--Interstate waters, the territorial seas, and waters that would or could affect interstate commerce, including tributaries of such waters and adjacent wetlands, as defined in Title 33, Code of Federal Regulations, Part 328.

(b) Certification Required. No person may conduct any activity subject to the jurisdiction of the commission pursuant to a Department of the Army permit or an NPDES permit if the activity may result in a discharge into waters of the United States within the boundaries of the State of Texas, unless the commission has first issued a certification or waiver of certification under this section.

(c) Request for Certification. The regional administrator, district engineer, or the permit applicant may submit a request for certification to the commission.

(1) Request by Applicant. If the permit applicant requests certification, the applicant shall submit to the commission:

(A) a copy of the completed permit application and any amendments thereto;

(B) a list on a map or on a separate sheet attached to a map of the names and addresses of owners of tracts of land adjacent to the site where the proposed activity would occur and, where the activity may result in a discharge to watercourse other than the Gulf of Mexico or a bay, the owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, except for those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(C) a request for certification; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(2) Request by EPA or the Corps. Except as provided in subsection (d)(1) of this section, a request for certification submitted by the regional administrator or the district engineer shall contain the information specified in this paragraph:

(A) a copy of the public notice;

(B) a request for certification;

(C) for NPDES permits, a copy of the draft permit, if available; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(3) Request for Additional Information. Where the commission believes more information is required to accomplish review of a request for certification, the commission shall notify the applicant or the permitting agency and request such information. In response to such a notification from the commission, the applicant or the permitting agency shall submit such materials as the commission finds necessary for review of the request for certification. Except as otherwise provided, such information shall be provided within ten days of issuance of a request for additional information by the commission.

(d) Notice of Request for Certification.

(1) Joint Notice. Notice of a request for certification shall be made using a joint mailed notice issued by the

U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency after agreements with those agencies have been reached regarding the content of the notice and the persons entitled to notice in Texas. When a joint notice is issued by either the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency, the requirements of subsection (c)(2) of this section do not apply.

(2) Notice by Applicant. If a joint notice is not used as provided in paragraph (1) of this subsection, the applicant must mail notice of the request for certification on or before the date the request for certification is filed with the commission. Such notice shall include the information required in paragraph (3) of this subsection. The applicant shall provide notice by first class mail to:

(A) the owners of land adjacent to the tract upon which the activity is proposed to take place, and where the activity may result in a discharge to a watercourse other than the Gulf of Mexico or a bay, the surface owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, excluding owners of those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(B) the mayor and health authorities of any city or town in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(C) the county judge and health authorities of any county in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(D) the Texas Commission on Environmental Quality (TCEQ) or its successor agencies;

(E) the Texas Parks and Wildlife Department;

(F) the U.S. Environmental Protection Agency, Region 6;

(G) the U.S. Fish and Wildlife Service; and

(H) for a proposed activity within the coastal management program boundary as defined under Title 31, Texas Administrative Code §503.1 (Coastal Management Program Boundary), the Secretary of the Coastal Coordination Council.

(3) Contents of Notice. Any notice provided as required in paragraph (2) of this subsection shall contain:

(A) the applicant's name and mailing address, together with the name and mailing address of the party conducting the activity, if different from the applicant;

(B) a brief written description of the activity;

(C) a statement that the applicant is seeking certification from the commission under the Federal Clean Water Act, §401;

(D) a statement that any comments concerning the request for certification may be submitted in writing to the assistant Director of Environmental Services, Railroad Commission, 1701 North Congress Avenue, P.O. Box 12967, Austin, Texas 78711-2967, on or before the deadline for submission of written public comments, which, absent special circumstances, shall be at least 30 days after the date notice is mailed; and

(E) a statement that a copy of the permit application is available for review in the office of the federal permitting agency.

(4) Emergency Actions. When the division engineer for the U.S. Army Corps of Engineers authorizes emergency procedures and it is in the public interest to provide a certification in less than 30 days, the commission may waive the notice and hearing requirements under this section and issue a final determination. For emergency actions within the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), the commission may only issue a final determination if the emergency action is consistent with the provisions of 31 TAC §501.14(j) (7) (Policies for Specific Activities and Coastal Natural Resource Areas).

(e) Public Comments.

(1) Written Comments. The commission shall consider all comments related to the water quality impacts of the proposed activity that are submitted to the commission in writing prior to the deadline for submission of comments.

(2) Public Meetings. The commission shall hold a meeting to receive public comment on a request for certification if the commission finds that such a meeting is in the public interest. If the commission holds a meeting to receive public comment on a request for certification, the commission shall notify the applicant by first class mail not less than ten days before the date set for the public meeting that a meeting to receive public comment will be held on the request for certification. The commission will also provide notice by first-class mail or by personal service to all of the persons identified under subsection (d) (2) of this section and the federal permitting agency at least ten days prior to the public meeting. The notice of public meeting shall identify the federal permit application; the date, time, place, and nature of the public meeting; the legal authority and jurisdiction under which the public meeting is to be held; the applicant's proposed action; the requirements for submitting written comments; the method for obtaining additional information; and such other information as the commission deems necessary. The notice to the federal permitting agency shall also estimate the additional time necessary to consider the request for certification and shall state that the commission is not waiving certification.

(f) Commission Review of Requests for Certification. After expiration of the time for receipt of public

comments, the commission shall determine whether the proposed activity for which a request for certification has been received will result in any discharge into waters of the United States within the boundaries of the State of Texas, and if so, whether the proposed activity will comply with all applicable water quality requirements. Applicable water quality requirements include, but are not limited to, state water quality standards, and any other applicable water quality requirements. For an activity within the boundary of the Texas Coastal Management Program (CMP), applicable state water quality requirements include the enforceable goals and policies of the CMP, Title 31, Texas Administrative Code, Chapter 501.

(g) Final Action.

(1) Issuance of Final Determination. A final determination on a request for certification of an NPDES or Department of the Army permit shall be issued by the commission within 15 days from the close of the public comment period, unless the regional administrator or the district engineer, in consultation with the commission, finds that unusual circumstances require a longer time. If the commission does not act upon the request for certification within 15 days from the close of the public comment period or within a longer time granted by the regional administrator or the district engineer, the commission will be deemed to have waived certification. Notwithstanding any contrary provisions of this paragraph, in unusual circumstances the commission may elect to delay acting upon a request for certification of an NPDES permit until after a review of the draft permit.

(2) Notification of Final Determination. The commission shall notify the applicant, the regional administrator or district engineer, and any person so requesting of its final determination. Such final determination shall waive, grant, grant conditionally or deny certification. The notification of a final determination shall be in writing and shall include:

(A) the name and address of the applicant;

(B) a statement of conditions that are necessary to ensure compliance with the applicable water quality requirements;

(C) when the state certifies a draft permit instead of a permit application, any condition required to ensure compliance with applicable water quality requirements shall be identified, citing the federal or state law references upon which that condition is based. Failure by the commission to provide such a citation waives its right to certify with respect to that condition;

(D) for NPDES permits, a statement of the extent to which each condition of the draft permit can be made less stringent without the concurrence of the commission; and

(E) a statement of the basis for the commission's determination to waive certification, grant certification, grant conditional certification, or deny certification.

(3) Statement of Basis.

(A) If a waiver of certification is made, the statement of basis for the commission's determination shall explain that the waiver is based on a determination that no discharge will result from the activity or that the activity does not fall within the commission's jurisdiction or that the commission expressly waives its authority to act on a request for certification for other reasons.

(B) If a certification or conditional certification is made, the statement of basis for the commission's determination shall include either a statement that there is reasonable assurance that the activity will be conducted in a manner which will not violate any applicable water quality requirements or a statement of conditions, including monitoring conditions, that the commission deems necessary to assure that the discharge will not violate applicable water quality requirements.

(C) If a denial of certification is made, the statement of basis for the commission's determination will explain why the commission has determined that the proposed activity will result in a violation of applicable water quality requirements.

(4) Limitation. The commission shall not condition or deny certification of an NPDES permit on the grounds that state law allows a less stringent permit condition.

(5) Request for Hearing. If the commission's final determination denies certification, the applicant may request a hearing on the final determination. If the commission's final determination grants a conditional certification and the applicant disagrees with one or more of such conditions, the applicant may request a hearing on the final determination. A request for a hearing must be filed within 15 days after the commission issues its final determination. The commission shall provide notice of the hearing to each of the parties provided notice of the final determination as provided in paragraph (2) of this subsection. After hearing, the examiner shall recommend a final action by the commission.

(h) Penalties. Violations of this section may subject a person to penalties and remedies specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the commission. 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) (Statewide Rule 73) for violation of this section.

Source Note: The provisions of this §3.93 adopted to be effective October 25, 1995, 20 TexReg 8445; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.95 Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations

(a) Definitions. The following terms, when used in this

section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or for amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine string--The uncemented tubing through which highly saline water flows into or out of a hydrocarbon storage well during hydrocarbon withdrawal or injection operations.

(3) Cavern--The storage space created in a salt formation by solution mining.

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

(5) Emergency shutdown valve--A valve that automatically closes to isolate a hydrocarbon storage wellhead from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(6) Fire detector--A device capable of detecting the presence of a flame or the heat from a fire.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground hydrocarbon storage facility is not considered fresh water.

(8) Hydrocarbon storage well or storage well--A well, including the storage wellhead, casing, tubing, borehole, and cavern, used for the injection or withdrawal of liquid or liquefied hydrocarbons into or out of an underground hydrocarbon storage facility.

(9) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(10) Liquid or liquefied hydrocarbons--Crude oil and products, derivatives, or byproducts of oil or gas that are:

(A) liquid under standard conditions of temperature and pressure;

(B) liquefied under the temperatures and pressures at which they are stored; or

(C) stored under conditions that necessitate the use of displacement fluids to withdraw them from storage.

(11) Operator--The person recognized by the Commission as being responsible for the physical operation of an underground hydrocarbon storage facility, or such person's authorized representative.

(12) Owner--The person recognized by the Commission as owning all or part of a storage facility, or such person's authorized representative.

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

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

(15) Process or transfer area--Any area at an underground hydrocarbon storage facility where hydrocarbons are physically altered by equipment, including dehydrators, compressors, and pumps, or where hydrocarbons are transferred to or from trucks, rail cars, or pipelines.

(16) Storage wellhead--Equipment installed at the surface of the wellbore, including the casinghead and tubing head, spools, block or wing valves, and instrument flanges. Spool pieces must have a length of less than six feet to be considered a part of the storage wellhead.

(17) Surface piping--Any pipe within a storage facility that is directly connected to a storage well, outboard of the wellhead emergency shutdown valve and used to transport product, brine, or fresh water to or from a storage well whether such pipe is above or below ground level.

(18) Underground hydrocarbon storage facility or storage facility--A facility used for the storage of liquid or liquefied hydrocarbons in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground hydrocarbon storage facility without obtaining a permit from the Commission. A permit issued by the Commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the Commission, or until it expires by its terms. The provisions of this section apply to permits for underground hydrocarbon storage facility operations issued prior to the effective date of this section, except as specifically provided in this section.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a Commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground hydrocarbon storage facility shall be filed with the Commission by the owner or operator, or proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with the applicable state laws and Commission regulations.

(2) Permit amendment. An application for amendment of an existing underground hydrocarbon storage facility permit shall be filed with the Commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional hydrocarbon storage wells;

(D) prior to any increase in the volume of liquid or liquefied hydrocarbons stored in the cavern in excess of the permitted storage volume; or

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

(3) Increase in capacity. The owner or operator of a storage facility shall notify the Commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the Commission within 10 days of the date that the owner or operator knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the Commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground hydrocarbon storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(4) Related activities. An application for a permit to store saltwater or brine in a pit or to dispose of saltwater or other oil and gas waste arising out of or incidental to the creation, operation, or maintenance of an underground hydrocarbon storage facility shall be filed in accordance with applicable Commission requirements.

(d) Standards for underground storage zone.

(1) Geologic, construction, and operating performance. An underground hydrocarbon storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored hydrocarbons, uncontrolled escape of hydrocarbons, pollution of fresh water, and danger to life or property. Natural gas storage operations are not authorized under the provisions of this section. A permit under §3.97 of this title (relating to Underground Storage of Gas in Salt Formations) is required to convert from storage of liquid or liquefied hydrocarbons to storage of natural gas in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. The applicant shall, no later than the date the application is mailed to or filed with the Commission, give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the Commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in

the county or counties where the facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the Commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground hydrocarbon storage facility will be considered for approval only after notice and hearing. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the Commission receives no protest from a person notified pursuant to the provisions of paragraph (1) of this subsection, or from any other affected person.

(B) If the Commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the Commission, or of the date of the third publication, whichever is later, or if the Commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The Commission will schedule a hearing on the application upon written request of the applicant. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the Commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the Commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

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

(C) there are material violations of the terms and provisions of the permit or Commission regulations;

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

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent dangers. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the Commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the Commission or its designee. Until such transfer is approved by the Commission or its designee, the proposed transferee may not conduct any activities otherwise authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file a request for transfer of the permit with the Commission. Such request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the Commission.

(2) Approval. The Commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied Commission enforcement order at the time of the request for permit transfer; and

(B) there are no existing violations of any Commission regulation, order, or permit at the storage facility at the time of the request for permit transfer that have been documented by the Commission, or its

employees, unless the proposed transferee agrees to correct the violations according to a compliance schedule approved by the Commission, or its designee.

(3) Good cause. Notwithstanding paragraph (2) of this subsection, for good cause shown the Commission or its designee may require public notice and opportunity for hearing prior to taking action on a request for transfer of a permit. Such request may be denied after notice and opportunity for hearing if the Commission or its designee finds that transfer of the permit would not be in the public interest.

(h) Safety. The following safety requirements shall apply to all underground hydrocarbon storage facilities, except as specifically provided otherwise, provided, however, that the provisions of this subsection shall not apply to any hydrocarbon storage well that is out of service and disconnected from all surface piping. Notwithstanding the compliance time periods specified in this subsection, a new storage facility permitted under this section must have all required safety measures and equipment in place before commencement of storage operations at the facility. All storage facilities that are permitted on the effective date of this section must have such safety measures and equipment in place within the period of time specified. Further, until such a facility has all the safety measures and devices required by paragraphs (2) - (7) and (13) - (16) of this subsection in place, the facility must have an attendant on site at all times. Notwithstanding the compliance time periods specified in paragraph (2)(B) of this subsection, no storage well in active service may be operated without a fully functional emergency shutdown valve unless in compliance with specified conditions of paragraph (2)(C) of this subsection.

(1) Monitoring of injection and withdrawal operations. All hydrocarbon injection and withdrawal activities shall be continuously monitored by an individual who is trained and experienced in such activities. Any facility that is unattended during injection and withdrawal activities shall have company personnel on call at all times. On-call personnel must be able to reach the facility within 30 minutes from the time a potential problem at the storage facility is noted by the individual monitoring the injection or withdrawal activities.

(2) Storage wellhead.

(A) The storage wellhead shall be designed, operated, and maintained to contain the contents of the storage well and protect against loss of stored product.

(B) Within five years of the effective date of this section, the operator shall have installed emergency shutdown valves between the storage wellhead and the product and brine surface piping of each hydrocarbon storage well and, if required under paragraph (3) of this subsection, between the storage wellhead and fresh water surface piping of the well. Within one year of the effective date of the section, an operator may request an exception to the storage wellhead configuration or compliance date of this subparagraph and propose an alternative configuration or workover schedule for approval by the Commission or its designee. A storage well that is out of service and is disconnected from surface piping shall be exempt from this requirement until reactivated for active hydrocarbon storage. Emergency shutdown valves shall meet the following requirements.

(i) Each emergency shutdown valve shall be capable of activation at each storage well, at the on-site control center if one exists, at the remote control center if one exists, and at a location that is reasonably anticipated to be accessible to emergency response personnel at any facility that does not have an on-site control center that is attended 24 hours per day.

(ii) Each emergency shutdown valve shall be an automatic fail-closed valve that automatically closes when there is a loss of pneumatic pressure, hydraulic pressure, or power to the valve.

(iii) Each emergency shutdown valve shall be closed and opened at least monthly.

(iv) Each emergency shutdown valve system shall be tested at least twice each calendar year at intervals not to exceed 7 1/2 months. The test shall consist of activating the actuation devices, checking the warning system, and observing the valve closure.

(C) If an emergency shutdown valve system fails to operate as required, the storage well shall be immediately shut in until repairs are completed, unless:

(i) a backup emergency shutdown valve is in operation on the same piping; or

(ii) an attendant is posted at the well site to provide immediate manual shut-in.

(D) The requirements of this paragraph do not apply to underground hydrocarbon storage facilities storing only crude oil.

(3) Product, brine, and fresh water surface piping.

(A) Product surface piping shall be designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well. For facilities with hazardous materials surface piping under the administrative authority of the Safety Division of the Railroad Commission of Texas, for the purposes of this section, product surface piping extends from the wellhead emergency shutdown valve to the first pressure regulation device, including a manual, motor-operated, or emergency shutdown valve.

(B) Brine surface piping shall be designed for the maximum brine wellhead pressure and to transport, under emergency conditions, product to the brine system gas vapor control system described in paragraph (6) of this subsection unless:

(i) a secondary emergency shutdown valve is in operation on the brine surface piping; and

(ii) the brine surface piping between the wellhead emergency shutdown valve and the secondary emergency shutdown valve is designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well.

(C) Fresh water surface piping, if any, must be equipped with a wellhead emergency shutdown valve unless it is:

(i) disconnected from the wellhead; or

(ii) connected to brine surface piping outboard of the wellhead emergency shutdown valve; or

(iii) designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well; and has an internal diameter of less than or equal to two inches; and an attendant is posted at the well site to provide immediate manual shut-in when in use.

(D) Fresh water piping designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well and with an internal diameter of less than or equal to two inches is exempt from the requirement that an emergency shutdown valve be located on the wellhead or separated from the wellhead by a spool no longer than six feet.

(4) Overfill detection and automatic shut-in methods.

(A) The requirements of this paragraph shall not apply to an underground hydrocarbon storage facility storing only crude oil.

(B) The requirements of this paragraph shall not apply to a storage well that is out of service and disconnected from surface piping until the well is reconnected for hydrocarbon storage.

(C) Within one year of the effective date of this section, each storage cavern shall have at least two of the following redundant devices or methods in operation:

(i) a safety casing or annular tubing string filled with a non-volatile fluid and equipped with a pressure sensor switch set to automatically close all emergency shutdown valves in response to a preset pressure;

(ii) a preset pressure sensor switch or transducer on the brine piping that is set to automatically close all emergency shutdown valves in response to a preset pressure. This pressure sensor or transducer may be used in conjunction with weep hole(s) on a safety string that is concentric with the brine string, or in conjunction with weep hole(s) on the brine string;

(iii) a device on the brine string or brine piping that detects hydrocarbon in the brine by physical or chemical characteristics and that is set to automatically close all emergency shutdown valves in response to hydrocarbon detection;

(iv) an instrument that detects a rapid increase in the brine flow rate indicative of hydrocarbon in the brine and that is set to automatically close all emergency shutdown valves in response to a preset flow rate or differential flow rate; or

(v) an alternate device or method approved by the Commission or its designee.

(5) Leak detectors.

(A) The provisions of subparagraphs (B) - (D) of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) A leak detector shall be installed and in operation at the wellhead of each hydrocarbon storage well and at each process and transfer area and each surface vessel area that contains liquid or liquefied hydrocarbons. These leak detectors shall be integrated with the warning system required in paragraph (13)(A) of this subsection.

(C) Leak detectors shall be installed and in operation at four locations that are evenly spaced around the perimeter of the brine pit(s).

(D) Leak detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(6) Brine system gas vapor control.

(A) The provisions of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) Gas vapor control devices shall be installed and in operation at each brine pit system to ignite or capture hydrocarbon vapors that are heavier than air. Control devices shall consist of at least one of the following:

(i) a flare on the brine system upstream from the brine discharge point;

(ii) a hydrocarbon liquid knockout vessel and degasifier;

(iii) pilot lights on the berm of each brine pit; or

(iv) an alternative method designed to provide a reliable, localized point of ignition to prevent the formation of a vapor cloud.

(C) Brine system gas vapor control systems shall be inspected twice each calendar year at intervals not to exceed 7 1/2 months.

(7) Fire detection devices or methods and fire control systems.

(A) Fire detection devices or methods shall be

installed and in operation at all process and transfer areas. Fire detection devices or methods specified in this paragraph shall be integrated with the warning system required in paragraph (13)(A) of this subsection. Fire detection shall consist of at least one of the following:

(i) fire detectors;

(ii) heat sensors, including meltdown and fused devices; or

(iii) camera surveillance at facilities that are attended at an on-site control room 24 hours per day.

(B) Fire detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(C) Within three years of the effective date of this section, each storage wellhead in active storage service shall have fire suppression capability designed to aid in personnel rescue and for equipment protection and cooling. Within one year of the effective date of this section, the operator may request an exception to the schedule or fire suppression requirement of this subparagraph and propose an alternative schedule or means of protection from wellhead fire for approval of the Commission or its designee.

(8) Emergency response plan. Each storage facility shall submit to the Commission a written emergency response plan. The plan shall address spills and releases, fires, fire suppression capability, explosions, loss of electricity, and loss of telecommunication services. The plan shall describe the storage facility's emergency response communication system, procedures for coordination of emergency communication and response activities with local emergency planning committees and other local authorities, use of warning systems, procedures for citizen and employee emergency notification and evacuation, and employee training. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the Commission or its designee requires. The plan shall include a plat of the facility that shows the location of wells, processing areas, loading racks, brine pits, and other significant features at the site. A copy of the plan shall be provided to the local emergency response planning committee and to any other local governmental entity that submits a written request for a copy of the plan to the operator. Copies of the plan shall also be available at the storage facility and at the company headquarters.

(9) Notification of emergency or uncontrolled release.

(A) Emergency response personnel. Each operator shall notify the county sheriff's office, the county emergency management coordinator, and any other appropriate public officials, which are identified in the emergency response plan, of any emergency that could endanger nearby residents or property. Such emergencies include, but are not limited to, an uncontrolled release of hydrocarbons from a storage well, or a leak or fire at any area of the storage facility. The operator shall give notice as soon as practicable following the discovery of the emergency. At the time of the notice, the operator shall report an assessment of the potential threat to the public.

(B) Commission. The operator shall report to the appropriate Commission district office as soon as practicable any emergency, significant loss of fluids, significant mechanical failure, or other problem that increases the potential for an uncontrolled release. The operator shall file with the Commission within 30 days of the incident a written report on the root cause of the incident. The operator shall file with the Commission within 90 days of the incident a written report that describes the operational changes, if any, that have been or will be implemented to reduce the likelihood of a recurrence of a similar incident. An operator may request that the Commission grant, for good cause, a reasonable amount of additional time to file a written report on the root cause of the incident.

(10) Public education. Each facility operator shall establish a continuing educational program to inform residents within a one-mile radius of a hydrocarbon storage facility of emergency notification and evacuation procedures.

(11) Annual emergency drill. Annually, each operator shall conduct a drill that tests response to a simulated emergency. Written notice of the drill shall be provided to the appropriate Commission district office, the county emergency management coordinator, and the county sheriff's office at least seven days prior to the drill. Local emergency response authorities shall be invited to participate in all such drills. The operator shall file a written evaluation of the drill and plans for improvements with the appropriate district office and the county emergency management coordinator within 30 days after the date of the drill.

(12) Employee safety training.

(A) Each operator shall prepare and implement a plan to train and test each employee at each underground hydrocarbon storage facility on operational safety to the extent applicable to the employee's duties and responsibilities. The facility's emergency response plan shall be included in the training program.

(B) Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at an underground hydrocarbon storage facility. Emergency measures, including safety and evacuation measures specific to the contractor's work, shall be explained in the contractor safety meeting.

(13) Warning systems and alarms.

(A) All leak detectors, fire detectors, heat sensors, pressure sensors, and emergency shutdown instrumentation shall be integrated with warning systems that are audible and visible in the local control room and at

any remote control center. The circuitry shall be designed so that failure of a detector or heat sensor, excluding meltdown and fused devices, to function will activate the warning.

(B) A manually operated alarm shall be installed at each attended storage facility. The alarm shall be audible in areas of the facility where personnel are normally located.

(14) Wind socks. At least one wind sock that is visible at any time from any normal work location within the storage facility shall be installed at the facility.

(15) Barriers. Barriers designed to prevent unintended impact by vehicles and equipment shall be placed around above-grade hydrocarbon piping, hydrocarbon process equipment, and surface hydrocarbon storage vessels in areas where vehicles may normally be expected to travel or within 100 feet of a public road.

(16) Wellhead, surface piping, and associated valves. All wellhead equipment, product, fresh water, and brine surface piping, and associated valves shall be designed, installed, and operated in accordance with engineering standards to the expected service conditions to which the piping and equipment will be subjected.

(i) Cavern capacity and configuration.

(1) Crude oil storage. The provisions of this subsection shall not apply to underground hydrocarbon storage facilities where only crude oil is stored.

(2) Before storage operations begin. The capacity and configuration of each hydrocarbon storage cavern (both salt domes and bedded salt) shall be determined by sonar survey before storage operations begin in a newly completed cavern.

(3) Salt domes. The capacity and configuration of each salt dome hydrocarbon storage cavern shall be determined by sonar survey at least once every 10 years.

(4) Bedded salt. The configuration of the roof of each hydrocarbon storage cavern in bedded salt shall be determined by downhole log or an alternate method approved by the Commission or its designee at least once every five years.

(5) Filing results. Sonar and roof monitoring survey results shall be filed with the Commission within 30 days after the survey.

(6) Out-of-service caverns. A sonar or roof monitoring survey is not required for a cavern that is out of service. A sonar or roof monitoring survey shall be performed before any cavern that has been out of service is returned to service, unless the provisions of paragraph (2) of this subsection apply.

(j) Well completion, casing, and cementing. Hydrocarbon storage wells shall be cased and the casing strings cemented to prevent fluids from escaping to the surface or into fresh water strata, or otherwise escaping and causing waste or endangering public safety or the environment.

(1) New wells.

(A) All hydrocarbon storage wells drilled in salt domes after the effective date of this section shall have at least two casing strings cemented into the salt formation. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface, or from the casing shoe to a point at least 200 feet above the shoe of the previous casing string.

(B) All hydrocarbon storage wells in bedded salt drilled after the effective date of this section shall have all casing strings cemented with sufficient cement to fill the annular space outside each casing string from the casing shoe to the ground surface.

(2) Well completion report. A well completion report shall be filed in accordance with the instructions on the form prescribed by the Commission within 30 days after a storage well is completed and before solution mining to create the cavern begins.

(k) Operating requirements.

(1) Operating pressure. The operating pressure of each hydrocarbon storage well shall not exceed the permitted maximum allowable operating pressure for that well. The permitted maximum allowable operating pressure is that pressure specified in the Commission permit or order, or, if not specified in the permit or order, that pressure stated in the application or the application for amendment to a permit or order. The maximum operating pressure at the shoe of the lowermost cemented casing shall not exceed 0.8 pounds per square inch per foot of depth.

(2) Volume of hydrocarbons stored. The quantity of hydrocarbons stored in a cavern shall not exceed the permitted maximum storage volume for that cavern. The permitted maximum hydrocarbon storage volume is that volume specified in the Commission permit or order, or, if not specified in the permit or order, that volume stated in the application or the application for amendment to a permit or order.

(l) Monitoring requirements.

(1) Pressures. Each hydrocarbon storage well shall be equipped with pressure sensors that continuously monitor and display wellhead pressures on both the product and brine sides of the wellhead at the control room. Each hydrocarbon storage well with a safety string shall be equipped with a pressure sensor and the sensor shall continuously monitor the pressure on the safety string at the wellhead.

(2) Pressure gauges. Each hydrocarbon storage well shall be equipped with gauges on both the brine and

hydrocarbon sides of the wellhead.

(3) Volumes injected and withdrawn. The volume of hydrocarbons injected into and withdrawn from each hydrocarbon storage well shall be measured by:

(A) flow meter for each well; or

(B) an alternate method approved by the Commission or its designee.

(4) Measurement performance. The accuracy of hydrocarbon volume measurement devices or methods required under paragraph (3) of this subsection shall be verified at least once each year by a person who is not an officer or employee of the owner or operator, or any affiliate of the owner or operator. For purposes of this section, an affiliate is any person or entity that owns, is owned by, or is under common ownership with the owner or the operator. In the case of meters, verification includes witnessing meter calibration or proving conducted by the owner or operator or an affiliate of the owner or operator.

(5) Data recording. Within three years of the effective date of this section, operators shall have installed and have functioning equipment to electronically record all liquid and gas pressures, volumes, and flow rates at a frequency of at least once per minute, and all actuations of the emergency shutdown valve.

(m) Reporting. The operator shall report maximum wellhead pressures on the hydrocarbon and brine sides of each hydrocarbon storage well and the net volumes of hydrocarbons injected into and withdrawn from each hydrocarbon storage well in accordance with the instructions on the annual report form prescribed by the Commission.

(n) Operations, construction, and maintenance records retention.

(1) Hydrocarbon injection and withdrawal data.

(A) The operator shall retain for at least three months all electronic records of hydrocarbon storage well pressures, flow rates, and hydrocarbon volumes injected into and withdrawn from each well, and the hydrocarbon inventory of each cavern. These electronic data shall be recorded at a frequency of at least once per minute.

(B) The operator shall retain for at least five years the records, reported to the Commission under subsection (m) of this section, of maximum monthly wellhead pressures on the hydrocarbon and brine sides of each hydrocarbon storage well and the monthly net volumes of hydrocarbons injected into and withdrawn from each hydrocarbon storage well. These electronic data shall be recorded at a frequency of at least once per day.

(2) Records retention. The operator shall retain for at least five years the records of measurement performance under subsection (l)(4) of this section; and testing of safety devices under subsection (h) of this section. Records of any test of a safety device required under subsection (h) of this section shall be available for on-site inspection within 10 days of the date of the test.

(3) Construction and maintenance data. The operator shall retain for the life of the facility documents and records pertaining to the drilling, mining, completion, major repairs, and workovers of storage wells and testing of storage well integrity, and shall transfer all such documents and records to any new owner and/or new operator of the facility.

(4) Extension during investigation. Any documents or records that contain information pertinent to the resolution of any pending regulatory enforcement proceeding shall be retained beyond the prescribed retention until the resolution of such proceeding.

(o) Testing and maintenance.

(1) Integrity tests for wells in salt domes with a single casing string. Each hydrocarbon storage well drilled into a salt dome and having a single casing string cemented to the surface shall have the casing inspected by mechanical, ultrasonic, or magnetic methods at least once every five years and after each workover that involves physical changes to the cemented casing string.

(2) Integrity tests for wells other than those in salt domes with a single casing string. Each hydrocarbon storage well shall be tested for integrity prior to being placed into service, at least once every five years, and after each workover that involves physical changes to any cemented casing string. The following requirements apply to all such integrity tests.

(A) A hydrocarbon storage well shall be tested for integrity by the nitrogen-brine interface method or an alternative approved by the Commission, or its designee.

(B) A test procedure shall be filed with the Commission for approval at least 10 days before the test date.

(C) The operator shall notify the district office at least five days prior to conducting any integrity test.

(D) A complete record of each integrity test shall be filed in duplicate with the district office within 30 days after testing is completed. The record shall include a chronology of the test, copies of all downhole logs, storage well completion information, pressure readings, volume measurements, temperature logs and readings, and an explanation of the test results that addresses the precision of the test in terms of a calculated leak rate.

(E) Storage well pressures shall be allowed to stabilize to a rate of change of less than 10 psi in 24 hours before the testing period begins.

(3) Storage wellhead and casing. Storage wellhead

components and casing shall be inspected at least once every 10 years for corrosion, cracks, deformations or other conditions that may compromise integrity and that may not be detected by the five-year test. The operator may request an extension of up to five years from the Commission for good cause. Factors the Commission may consider in determining good cause pursuant to this paragraph include by are not limited to the age, location, and configuration of the well; well and facility history; operator compliance record; operator efforts to comply with this subsection; and accuracy of inventory control.

(4) Product, fresh water, and brine surface piping. Within one year of the effective date of this section, the operator shall submit a piping integrity management plan for approval by the Commission or its designee. Within three years of the effective date of this section, or in conjunction with the storage well integrity testing, all product, freshwater, and brine surface piping shall be maintained according to the facility's piping integrity management plan.

(5) Alternative monitoring. An operator may request the Commission or its designee to approve storage well pressure monitoring as an alternative to integrity testing for hydrocarbon storage wells that are out of storage service. An out-of-service storage well must be tested for integrity according to the procedures specified in paragraph (2) of this subsection before it may be returned to storage service.

(p) Plugging.

(1) Plug on abandonment. A hydrocarbon storage well shall be plugged upon permanent abandonment in a manner approved by the Commission or its designee. A proposal for plugging shall be submitted to the Commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file a notification of intent to plug at least five days prior to commencement of plugging operations. A plugging report shall be filed with the Commission in Austin within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a hydrocarbon storage well that has been permanently deactivated, an operator may request approval by the Commission or its designee of a plan to convert the storage well to a monitor well. A pressure monitoring plan must be submitted to the Commission along with the request to convert the storage well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in the Texas Natural Resources Code, Titles 3 and 11, and other statutes administered by the Commission.

(2) Certificate of compliance. The certificate of compliance for any underground hydrocarbon storage facility may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance).

(r) Applicability of other Commission rules and orders. The owner or operator of an underground hydrocarbon storage facility is not relieved by this section of compliance with any other requirement of Chapters 3, 4, 7, or 8 of this title (relating to Oil and Gas Division; Environmental Protection; Gas Services Division; or Pipeline Safety Regulations).

Source Note: The provisions of this §3.95 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 289; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.96 Underground Storage of Gas in Productive or Depleted Reservoirs

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

(1) Affected person--A person who, as a result of actions proposed an application for an underground gas storage project permit or an amendment or modification of an existing underground gas storage project permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

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

(3) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(4) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(5) Gas storage or underground gas storage--Storage of natural gas or other gaseous material in a productive or depleted reservoir, exclusive of gas injection for enhanced recovery.

(6) Gas storage project--All surface and subsurface rights, appurtenances, and improvements necessary for conducting underground gas storage operations in a gas storage reservoir.

(7) Gas storage well or storage well--A well used to inject or withdraw natural gas or other gaseous material stored in a productive or depleted reservoir, exclusive of a well used to inject gas for enhanced recovery.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of a gas storage project, or such person's authorized representative.

(9) Person--A natural person, corporation, organization, government, governmental subdivision or

agency, business trust, estate, trust, partnership, association, or any other legal entity.

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

(11) Productive or depleted reservoir--A subsurface sand, stratum, or formation that is productive of, or has previously produced, oil, gas, or geothermal resources.

(b) Permit required.

(1) General. No person may operate a gas storage project without obtaining a permit from the commission. A permit issued by the commission for operation of a gas storage project before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to gas storage projects permitted prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application. An application to operate a gas storage project shall be filed with the commission by the owner or operator or proposed owner or operator. The application shall include the following:

(1) compliance with safety requirements--information demonstrating compliance with the provisions of subsection (i) of this section;

(2) request for reservoir designation--a request for designation of a productive or depleted reservoir as a gas storage reservoir, supported by the following:

(A) information demonstrating that the reservoir is suitable for gas storage; and

(B) information demonstrating the amount of recoverable native gas remaining in the reservoir;

(3) compliance with standards for injection wells--information demonstrating compliance with the provisions of subsections (j), (k), and (l) of this section for each gas injection well. The requirements of this paragraph do not apply to wells used for gas withdrawal only;

(4) water protection letter--a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur in the project area;

(5) public interest--a request that the commission issue an order containing the findings described in the Texas Natural Resources Code, §91.174(a), if such an order is desired by the applicant;

(6) fees--the fees required under §3.78 of this title (relating to Fees and Financial Security Requirements) for each gas storage well in the storage project that will be used for injection.

(d) Permit amendment. An application for amendment of an existing gas storage project permit shall be filed with the commission as specified in paragraphs (1) - (4) of this subsection.

(1) Expansion of reservoir. An application for permit amendment shall be filed prior to expanding the areal extent of the gas storage reservoir.

(2) Increase in pressure. An application for permit amendment shall be filed prior to increasing the gas storage reservoir pressure above the maximum permitted pressure.

(3) Adding storage wells. An application for permit amendment shall be filed prior to adding additional gas storage wells to the project.

(4) Material deviation. An application for permit amendment shall be filed at any time that conditions at the storage project deviate materially from the conditions specified in the permit or permit application.

(e) Standards for storage reservoir. A gas storage project shall be operated only in a productive or depleted reservoir in a manner that will prevent waste of oil, gas, or geothermal resources, uncontrolled escape of gases, pollution of fresh water, and danger to life or property.

(f) Notice and hearing.

(1) Notice requirements. By no later than the date the application is mailed to or filed with the commission, the applicant shall give notice of an application for a permit to operate a gas storage project, or to amend an existing storage project permit, by mailing or delivering a copy of the application to:

(A) each mineral interest owner, other than the applicant, of the proposed gas storage reservoir;

(B) each leaseholder of minerals lying above or below the proposed gas storage reservoir;

(C) each leaseholder of minerals offsetting the proposed gas storage reservoir;

(D) each owner or leaseholder of any portion of the surface overlying the proposed gas storage reservoir;

(E) the clerk of the county or counties where the proposed gas storage reservoir is located; and

(F) the city clerk or other appropriate city official where the proposed gas storage reservoir is located within city limits.

(2) Publication of notice. Notice of the application for an original or amended gas storage project permit, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the gas storage project is located. The applicant shall file proof of publication of the notice prior to any hearing on the application or administrative approval.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. An application for a new gas storage project permit will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) If the commission receives a protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission or its designee determines that a hearing is in the public interest, then the applicant will be notified that the application for amendment cannot be administratively approved. The commission will schedule a hearing on the application upon request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(B) If the commission receives no protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person, the application may be approved administratively.

(C) If the application for amendment of a gas storage project permit is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(g) Modification, cancellation, or suspension of a permit.

(1) General. A permit may be modified, suspended, or canceled after notice and opportunity for hearing under any of the following circumstances:

(A) a material change in conditions has occurred in the operation of the gas storage project, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

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

(C) there are material violations of the terms and provisions of the permit or of applicable commission orders or regulations;

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

(E) injected fluids are escaping or are likely to escape from the storage project.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a permit for underground gas storage until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All underground gas storage operations shall cease upon suspension of a permit under this paragraph.

(h) Transfer of permit. A gas storage project permit may be transferred from one operator to another operator if both of the following requirements are met.

(1) Notice. Written notice of intended permit transfer is submitted to the commission at least 15 days prior to the date the transfer takes place.

(2) No objection. The commission or its designee does not notify the present permit holder of an objection to the transfer prior to the transfer date stated in the notification in paragraph (1) of this subsection.

(i) Safety requirements for gas storage projects.

(1) Leak detectors.

(A) Within two years of the effective date of this section, leak detectors shall be installed and in operation at each gas storage well that is located 100 yards or less from a residence, commercial establishment, church, school, or small, well-defined outside area, and at each structurally enclosed compressor site. For purposes of this section, the term "small, well-defined outside area" means an area such as a playground, recreation area, outdoor theater, or other place of public assembly that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

(B) Each leak detector required under this paragraph shall be tested twice each calendar year at intervals not to exceed 7-1/2 months and, when defective, repaired or replaced within 10 days.

(2) Warning systems. Within two years of the effective date of this section, all leak detectors required in paragraph (1) of this subsection shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a detector or pressure monitor to function will activate the warning.

(3) Emergency response plan. Within six months of the effective date of this section, each operator shall submit to the commission a safety plan that includes emergency response procedures, provisions to provide security against unauthorized activity, and gas release detection and prevention measures. The plan shall include a description of and be designed for the residential, commercial, and public land use in the proximity of the gas storage project. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the commission or its designee requires. Copies of the plan shall be available at the storage facility and at the company headquarters.

(4) Safety training. Within six months of the effective date of this section, each operator shall prepare and implement a plan to train and test each employee at each gas storage project on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The plan shall be incorporated into the plan addressing the requirements of the United States Department of Transportation and Occupational Safety and Health Administration. Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at a gas storage project. Emergency measures specific to the contractor's work shall be explained in the contractor safety meeting.

(5) Gas withdrawal wells exempt. Gas storage wells that will be used only for gas withdrawal are exempt from the requirements of paragraphs (1) and (2) of this subsection.

(j) Area of review. The applicant shall review the data of public record for wells that penetrate the portion of the gas reservoir that falls within the area proposed to be designated as the gas storage reservoir, and those wells that penetrate the gas reservoir within 1/4 mile of the outer boundary of the proposed gas storage reservoir, to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the gas storage reservoir. 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.

(k) Casing. Gas storage wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements).

(l) Special equipment.

(1) Tubing and packer. New wells drilled or converted for injection of gases after April 1, 1982, 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 fresh water.

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

(3) Exceptions. An exception to any provision of this subsection may be granted administratively upon a showing of good cause. If a request for an exception is administratively denied, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(m) Well record. Within 30 days after the completion, conversion, or recompletion of a gas storage 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.

(n) Monitoring and reporting.

(1) Wellhead pressure. The wellhead pressure of each gas storage well shall be continuously recorded, continuously monitored electronically, or controlled by a preset high-low pressure sensor switch.

(2) Pressure reporting. Information regarding wellhead pressures for each gas storage well shall be reported annually to the commission on the prescribed form.

(3) Gas metering. The total volume of gas injected into and withdrawn from the storage project shall be metered through a master meter.

(4) Record retention. All wellhead pressure records, gas metering records, and leak detector test results shall be

retained by the operator for at least five years.

(5) Reporting of leaks. The operator shall report to the appropriate district office the discovery of any pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the gas storage reservoir. Such report shall be made orally as soon as practicable following the discovery of the leak, and shall be confirmed in writing within five working days.

(6) Gas volume reports. On or before the last day of each month, the operator of each gas storage project that stores gas to supply a public utility shall file with the commission a report showing the volume of gas placed into storage and the volume of gas removed from storage at the project during the preceding month. The report shall also state the total volume of gas stored on the first and last days of the preceding month. This report shall be filed in a format acceptable to the commission.

(o) Integrity testing.

(1) Prior to commencing operations. Before beginning gas injection operations, the operator shall pressure test the long string casing, or the tubing-casing annulus if the well is equipped with tubing set in a packer. Gas storage wells in which injection occurs through casing shall be tested at the maximum authorized injection pressure. Gas storage wells in which injection occurs through tubing and packer shall be tested at no less than 500 psig.

(2) Subsequent tests. Each gas storage well shall be pressure tested in the manner provided in paragraph (1) of this subsection at least once every five years to determine if there are leaks in the casing, tubing, or packer. The commission, or its designee, may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with this requirement.

(3) Alternatives to testing. As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and monitoring results described in the annual monitoring report required by subsection (n) of this section, provided that there is no indication of problems with the well. The commission, or its designee, may also grant an exception for other viable alternative tests or surveys.

(4) District office notification. The operator shall notify the appropriate district office at least 48 hours prior to conducting the test required in paragraphs (1) or (2) of this subsection. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

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

(6) Gas withdrawal wells exempt. Gas storage wells that shall be used only for gas withdrawal are excluded from the requirements of this subsection.

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

(q) Penalties.

(1) General. Violations of this section may subject the operator to penalties and remedies specified in the Texas Natural Resources Code, Title 3; Texas Civil Statutes, Article 6053-3; and other statutes administered by the commission.

(2) Certificate of compliance. 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.

(r) Applicability of other commission rules.

(1) General. The operator of a gas storage project must comply with the requirements of Chapters 7 and 8 of this title (relating to Gas Services Division, and Pipeline Safety Regulations) for both pipelines and associated facilities, and other applicable commission rules and orders.

(2) Signs. Each location at which gas storage activities take place, including each gas storage well, shall be identified by a sign that meets the requirements specified in §3.3(a)(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign shall include a telephone number where the operator, or a representative of the operator, can be reached in the event of an emergency.

Source Note: The provisions of this §3.96 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.97 Underground Storage of Gas in Salt Formations

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

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Cavern--The storage space created in a salt formation by solution mining.

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

(4) Emergency shutdown valve--A valve that automatically closes to isolate a gas storage wellhead from

surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(5) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground gas storage facility is not considered fresh water.

(6) Gas storage well or storage well--A well, including the storage wellhead, casing, tubing, borehole, and cavern used for the injection or withdrawal of natural gas or any other gaseous substance into or out of an underground gas storage facility.

(7) Leak or fire detector--A device capable of detecting by chemical or physical means the presence of stored product gas or the escape of stored product gas or the presence of flame or heat of a fire.

(8) Operator--The person recognized by the Commission as being responsible for the physical operation of an underground gas storage facility, or such person's authorized representative.

(9) Owner--The person recognized by the Commission as owning all or part of an underground gas storage facility, or such person's authorized representative.

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

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

(12) Storage wellhead--Equipment installed at the surface of the wellbore, including the casinghead and tubing head, spools, block or wing valves, and instrument flanges. Spool pieces must have a length less than six feet to be considered a part of the storage wellhead.

(13) Surface piping--Any pipe within a storage facility that is directly connected to a storage well, outboard of the wellhead emergency shutdown valve and used to transport gas, brine, or fresh water to or from a storage well whether such pipe is above or below ground level.

(14) Underground gas storage facility or storage facility--A facility used for the storage of natural gas or any other gaseous substance in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground gas storage facility without obtaining a permit from the Commission. A permit issued by the Commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the Commission, or until it expires according to its terms. The provisions of this section apply to permits to conduct gas storage operations issued prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a Commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground gas storage facility shall be filed with the Commission by the owner or operator, or the proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with applicable state laws and Commission regulations.

(2) Permit amendment. An application for amendment of an existing underground gas storage facility permit shall be filed with the Commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional storage wells;

(D) prior to an increase in the maximum operating pressure above the permitted pressure; or

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

(3) Increase in capacity. The owner or operator of a storage facility shall notify the Commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the Commission within 10 days of the date that the owner or operator of the storage facility knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the Commission or its designee may take any one or more of

the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of gas, uncontrolled escape of gas, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground gas storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(d) Standards for underground storage zone.

(1) Geologic, construction, and operating performance. An underground gas storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored gases, uncontrolled escape of gases, pollution of fresh water, and danger to life or property. This section does not authorize storage of liquid or liquefied hydrocarbons in an underground salt formation. A permit under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) is required to convert from storage of natural gas to storage of liquid or liquefied hydrocarbons in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. The applicant shall, no later than the date the application is mailed to or filed with the Commission, give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

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

(F) if the storage facility is located or is proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the Commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the storage facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the Commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground gas storage facility will be considered for approval only after notice and hearing. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the Commission receives no protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person.

(B) If the Commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the Commission, or of the date of the third publication, whichever is later, or if the Commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The Commission will schedule a hearing on the application upon written request of the applicant. The Commission will give notice of the hearing to all affected persons, local

governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the Commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the Commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) pollution of fresh water is likely as a result of continued operation of the storage facility;

(C) there are material violations of the terms and provisions of the permit or Commission regulations;

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

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the Commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the Commission, or its designee. Until such transfer is approved by the Commission or its designee, the proposed transferee may not conduct any activities authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file with the Commission a request for transfer of the permit. Such a request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the Commission.

(2) Approval. The Commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied Commission enforcement order at the time of the request for permit transfer; and

(B) there are no existing violations of any Commission regulation, order, or permit at the storage facility at the time of the request for permit transfer that have been documented by the Commission, or its employees, unless the proposed transferee agrees to correct the violations according to a compliance schedule approved by the Commission, or its designee.

(3) Good cause. Notwithstanding paragraph (2) of this subsection, for good cause shown the Commission, or its designee, may require public notice and opportunity for hearing prior to taking action on a request for transfer of a permit. Such request may be denied after notice and opportunity for hearing if the Commission or its designee finds that transfer of the permit would not be in the public interest.

(h) Safety. The following safety requirements shall apply to all underground gas storage facilities, provided, however, that the provisions of this subsection shall not apply to any natural gas storage well that is out of service and disconnected from surface piping. Notwithstanding the compliance time periods specified in this subsection, a new underground gas storage facility permitted under this section must have all required safety measures and equipment in place before commencement of storage operations at the facility. All existing storage facilities must have such safety measures and equipment in place within the period of time specified. Notwithstanding the compliance time periods specified in paragraph (2)(B) of this subsection, no storage well in active service may be operated without a fully functional emergency shutdown valve unless in compliance with specified conditions of paragraph (2)(C) of this subsection.

(1) Monitoring of injection and withdrawal operations. All gas injection and withdrawal activities shall be continuously monitored by an individual who is experienced and trained in such activities. Any facility that is unattended during injection and withdrawal activities shall have company personnel on call at all times. On-call personnel must be able to reach the facility within 30 minutes from the time a potential problem is noted by the individual monitoring the injection or withdrawal activities.

(2) Storage wellhead.

(A) The storage wellhead must be designed, operated, and maintained to contain the contents of the storage well and protect against loss of stored product.

(B) Within five years of the effective date of this section, the operator shall have installed emergency shutdown valves between the wellhead and the gas injection/withdrawal surface piping of each storage well

and between the wellhead and any brine or fresh water surface piping. Within one year of the effective date of this section, the operator may request an exception to the storage wellhead configuration or compliance date of this subparagraph and propose an alternative configuration or workover schedule for approval by the Commission or its designee. A storage well that is out of service and is disconnected from surface piping shall be exempt from this requirement until reactivated for active gas storage. Emergency shutdown valves shall meet the following requirements:

(i) Each emergency shutdown valve shall be capable of activation at each storage well, at the on-site control center if one exists, at the remote control center if one exists, and at a location that is reasonably anticipated to be accessible to emergency response personnel at any facility that does not have an on-site control center that is attended 24 hours per day.

(ii) Each emergency shutdown valve shall be an automatic fail-closed valve that automatically closes when there is a loss of pneumatic or hydraulic pressure on, or power to, the valve or when the maximum operating pressure under subsection (k) of this section is exceeded.

(iii) Each emergency shutdown valve shall be closed and opened at least monthly.

(iv) Each emergency shutdown valve system shall be tested at least twice each calendar year at intervals not to exceed 7 1/2 months. The test shall consist of activating the actuation devices, checking the warning system, and observing the valve closure.

(C) If an emergency shutdown valve system fails to operate as required, the well shall be immediately shut in until repairs are completed, unless:

(i) a backup emergency shutdown valve is in operation on the same piping; or

(ii) an attendant is posted at the well site to provide immediate manual shut-in.

(3) Gas, brine, and fresh water surface piping.

(A) Gas surface piping shall be designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well. For facilities with hazardous materials surface piping under the administrative authority of the Safety Division of the Railroad Commission of Texas, for the purposes of this section, gas surface piping extends from the wellhead emergency shutdown valve to the first pressure regulation device, including a manual, motor-operated, or emergency shutdown valve.

(B) Brine piping, if any, shall be designed for the maximum brine wellhead pressure and to transport, under emergency conditions, gas to a gas control system if the operator is solution mining while the gas storage well is in active storage service, unless:

(i) a secondary emergency shutdown valve is in operation on the brine surface piping; and

(ii) the brine surface piping between the wellhead emergency shutdown valve and the secondary emergency shutdown valve is designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well.

(C) Fresh water surface piping, if any, must be equipped with an emergency shutdown valve unless it is:

(i) disconnected from the wellhead; or

(ii) connected to the brine surface piping outboard of the wellhead emergency shutdown valve; or

(iii) designed for the maximum allowable operating pressure on the hydrocarbon side of the well; and has an internal diameter of less than or equal to two inches; and an attendant is posted at the well site to provide immediate manual shut-in when in use.

(D) Fresh water piping designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well and with an internal diameter of less than or equal to two inches, is exempt from the requirement that an emergency shutdown valve be separated from the wellhead by a spool no longer than six feet.

(4) Cavern debrining and solution mining operations.

(A) Within one year of the effective date of this section, each storage well shall have two or more of the following redundant devices or methods in operation during cavern debrining operations or during solution mining operations that are conducted with gas in storage in the same cavern. These devices are designed to prevent the release of gas into the brine and fresh water systems connected to the well during cavern debrining operations or during solution mining operations that are conducted with gas in storage in the same cavern. Gas release prevention shall consist of at least two of the following redundant devices or methods:

(i) emergency shutdown valves equipped with pressure sensor switches or transducers set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to preset pressures on the brine and fresh water piping of the well;

(ii) weep hole(s) on the brine return string in conjunction with a preset pressure sensor switch or transducer on the brine piping that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to a preset pressure;

(iii) a device on the brine return string or brine piping that detects hydrocarbon in the brine by physical or

chemical characteristics and that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to hydrocarbon detection;

(iv) an instrument that detects a rapid increase in the brine flow rate indicative of hydrocarbon in the brine and that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to a preset flow rate or differential flow rate; or

(v) an alternative device or method approved by the Commission.

(B) Solution mining of a cavern may occur while gas is in storage, provided that the injection of fresh water and the injection of gas do not occur simultaneously within the same cavern.

(5) Leak or fire detectors.

(A) Within two years of the effective date of this section, a leak or fire detector shall be installed and in operation at each gas storage well and each structurally enclosed compressor site.

(B) Leak or fire detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months, and, when defective, repaired or replaced within 10 days. Leak or fire detectors shall be integrated with warning systems required in paragraph (6)(A) of this subsection.

(6) Warning systems and alarms.

(A) Within two years of the effective date of this section, all leak or fire detectors and sensors or methods that actuate the emergency shutdown valve shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a leak or fire detector to function will activate the warning.

(B) A manually operated audible alarm shall be installed at each attended storage facility. The alarm shall be audible in areas of the facility where personnel are normally located.

(7) Emergency response plan. Each storage facility shall submit to the Commission a written emergency response plan. The plan shall address gas releases, fires, fire suppression capability, explosions, loss of electricity, and loss of telecommunication services. The plan shall describe the facility's emergency response communication system, procedures for coordination of emergency communication and response activities with local authorities, use of warning systems, procedures for citizen and employee emergency notification and evacuation, and employee training. The plan shall also include a plat of the facility showing the locations of wells, processing areas, and other significant features at the facility. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the Commission or its designee requires. A copy of the plan shall be provided to the local emergency response committee and to any other local governmental entity that submits a written request for a copy of the plan to the operator. Copies of the plan shall also be available at the storage facility and at the company headquarters.

(8) Notification of emergency or uncontrolled release.

(A) Emergency response personnel. Each operator shall notify the county sheriff's office, the county emergency management coordinator, and any other appropriate public officials which are identified in the emergency response plan of any emergency that could endanger nearby residents or property. Such emergencies include, but are not limited to, an uncontrolled release of hydrocarbons from a storage well or a leak or fire at any area of the storage facility. The operator shall give notice as soon as practicable following the discovery of the emergency. At the time of the notice, the operator shall also report an assessment of the potential threat to the public.

(B) Commission. The operator shall report to the appropriate Commission district office as soon as practicable any emergency, significant loss of gas or fluids, significant mechanical failure, or other problem that increases the potential for an uncontrolled release. The operator shall file with the Commission within 30 days of the incident a written report on the root cause of the incident. Within 90 days of the incident, the operator shall file with the Commission a written report that describes the operational changes, if any, that have been or will be implemented to reduce the likelihood of a recurrence of a similar incident. An operator may request that the Commission grant, for good cause, a reasonable amount of additional time to file a written report on the root cause of the incident.

(9) Annual emergency drill. Annually, each operator shall conduct a drill that tests response to a simulated emergency. Written notice of the drill shall be provided to the appropriate Commission district office, the county emergency management coordinator, and the county sheriff's office at least seven days prior to the drill. Local emergency response authorities shall be invited to participate in all such drills. The operator shall file a written evaluation of the drill and plans for improvements with the appropriate district office and the county emergency management coordinator within 30 days after the date of the drill.

(10) Employee safety training.

(A) Each operator shall prepare and implement a plan to train and test each employee at each underground gas storage facility on operational safety to the extent applicable to the employee's duties and responsibilities. The facility's emergency response plan shall be included in the training program.

(B) Each operator shall hold a safety meeting with

each contractor prior to the commencement of any new contract work at an underground gas storage facility. Emergency measures, including safety and evacuation measures specific to the contractor's work, shall be explained in the contractor safety meeting.

(11) Fire suppression capability.

(A) Within three years of the effective date of this section, each operator shall have fire suppression capability designed to aid in personnel rescue and equipment protection and cooling.

(B) Within one year of the effective date of this section, the operator may request an exception to the schedule or fire suppression requirement of this paragraph and propose an alternative schedule or means of protection from wellhead fire for approval of the Commission or its designee.

(12) Wellhead, piping, and associated valves. All wellhead surface piping and associated valves shall be designed, installed, and operated in accordance with engineering standards to the expected service conditions to which the piping and equipment will be subjected.

(13) Barriers. Within one year of the effective date of this section, barriers designed to prevent unintended impact by vehicles and equipment shall be placed around above grade hydrocarbon piping, hydrocarbon process equipment where vehicles may normally be expected to travel, or within 100 feet of a public road.

(i) Cavern capacity and configuration.

(1) Before storage operations begin. The capacity and configuration of each gas storage cavern (both salt domes and bedded salt) shall be determined by sonar survey before storage operations begin in a newly completed cavern.

(2) Salt domes. The capacity and configuration of each salt dome gas storage cavern shall be determined by sonar survey before a cavern that has been out of service is returned to service, provided, however, that a sonar survey shall not be required on a cavern that is being returned to service if a sonar survey of that cavern has been run at any time during the previous 10 years.

(3) Bedded salt. The configuration of the roof of each gas storage cavern in bedded salt shall be determined by downhole log or an alternate method approved by the Commission, or its designee, at least once every five years.

(4) Filing of results. Sonar and roof monitoring survey results shall be filed with the Commission within 30 days after the survey.

(5) Out-of-service caverns. A sonar or roof monitoring survey is not required for a cavern that is out of service. A sonar or roof monitoring survey shall be performed before any such cavern that has been out of service is returned to service, unless the provisions of paragraph (2) of this subsection apply.

(6) Verification. Sonar surveys performed before debrining shall be verified by metering the volume of the displaced brine.

(j) Well completion, casing, and cementing. Gas storage wells shall be cased and the casing strings cemented to prevent gases from escaping to the surface or into fresh water strata, or otherwise escaping and causing waste or endangering public safety or the environment.

(1) New wells.

(A) All gas storage wells drilled in salt domes after the effective date of this section shall have at least two casing strings cemented into the salt formation. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface, or from the casing shoe to a point at least 200 feet above the shoe of the previous casing string.

(B) All gas storage wells drilled in bedded salt after the effective date of this section shall have all casing strings cemented with sufficient cement to fill the annular space outside each casing string from the casing shoe to the ground surface.

(2) Well completion report. A well completion report shall be filed in accordance with the instructions on the form prescribed by the Commission within 30 days after a storage well is completed and before solution mining to create the cavern begins.

(k) Operating pressure.

(1) Not to exceed maximum. The operating pressure of each gas storage well shall not exceed the permitted maximum allowable operating pressure for that well. The permitted maximum allowable operating pressure is that pressure specified in the Commission permit or order, or, if not specified in the permit or order, that pressure stated in the application or the application for amendment to a permit or order.

(2) At casing seat. The maximum operating pressure at the casing seat shall not exceed 0.85 pounds per square inch per foot of depth.

(l) Monitoring requirements.

(1) Gas pressure. Gas pressure on the injection/withdrawal casing or tubing or piping connected thereto shall be equipped with a pressure sensor to continuously monitor the wellhead pressure. Pressure sensors shall be integrated electronically with the warning systems, alarms, and emergency shutdown valve actuation system as required in subsection (h)(2)(B) and (h)(6)(A) of this section.

(2) Pressure observation valves. The

injection/withdrawal casing or tubing shall be equipped with a pressure observation valve and gauge. The wellhead shall be equipped with a pressure observation valve on each casing annulus so that a gauge may be installed for pressure monitoring.

(3) Volumes injected and withdrawn. The volume of gas injected into and withdrawn from each storage well shall be measured by:

(A) flow meter for each well; or

(B) an alternate method approved by the Commission.

(4) Meter calibration. Meters that measure the volume of gas into storage and out of storage shall be recalibrated at least once each year.

(5) Data recording. Within three years of the effective date of this section, operators shall have installed and have functioning equipment to electronically record all liquid and gas pressures and injection volumes and rates at a frequency of at least once per minute, and all actuations of the emergency shutdown valve.

(m) Reporting.

(1) Monthly reports. On or before the last day of each month, the operator of each facility that stores gas to supply a public utility shall file with the Commission a report showing the volume of gas placed into storage and the volume of gas removed from storage at the storage facility, during the preceding month. The report shall also state the total volume of gas in storage on the first and last days of the preceding month. This report shall be filed in a format acceptable to the Commission or its designee.

(2) Annual reports. The operator shall file annually a status report for each storage well in accordance with the instructions on the form prescribed by the Commission.

(n) Operations, construction, and maintenance records retention.

(1) Operations data.

(A) The operator shall retain for at least three months all electronic records of storage well pressures, volumes of gases injected and withdrawn, and the inventory of gas in storage. These electronic data shall be recorded at a frequency of at least once per minute.

(B) The operator shall retain for at least five years the records reported to the Commission under subsection (m). These electronic data shall be recorded at a frequency of at least once per day.

(2) Records retention. The operator shall retain for at least five years the records of measurement performance under subsection (l)(4) of this section; and testing of safety devices under subsection (h) of this section. Records of any test of a safety device required under subsection (h) of this section shall be available for on-site inspection within 10 days of the date of the test.

(3) Construction and maintenance data. The operator shall retain for the life of the facility documents and records pertaining to the drilling, mining, completion, repair and workover of storage wells and the testing of storage well integrity, and shall transfer all such documents and records to any new owner and/or new operator of the facility.

(4) Extension during investigation. The operator shall retain beyond the prescribed retention period any documents or records that contain operational data pertaining to the resolution of any pending regulatory enforcement proceedings until the resolution of such proceedings.

(o) Testing and maintenance.

(1) Integrity tests. Each gas storage well shall be tested for integrity prior to being placed into service, at least once every five years, and after each workover that involves physical changes to any cemented casing string. The following requirements apply to such integrity tests.

(A) A test procedure shall be filed with the Commission for approval at least 10 days before the test date.

(B) The initial test conducted on a well prior to placing it into service shall be performed using the nitrogen-interface test method or an alternative method approved by the Commission or its designee.

(C) The integrity test required to be conducted at least once every five years on a well that has gas in storage may be performed using pressure monitoring, provided:

(i) the wellhead pressure is stabilized such that the effects of ambient temperature on pressure have overtaken the effects of the last injection or withdrawal on pressure;

(ii) a downhole temperature log is run at the beginning and at the end of the test period;

(iii) the test period is a minimum of 72 hours; and

(iv) the net gas volume change for the test period is calculated.

(D) The operator shall notify the district office at least five days prior to conducting any integrity test.

(E) A complete record of each integrity test shall be filed in duplicate with the district office within 30 days after testing is completed. The record shall include a chronology of the test, copies of all downhole logs, storage well completion information, pressure readings, volume measurements, temperature logs and readings, and an explanation of the test results that addresses the precision

of the test in terms of a calculated leak rate.

(2) Alternative monitoring. An operator may request the Commission or its designee to approve well pressure monitoring as an alternative to integrity testing for storage wells that are out of gas storage service. An out-of-service well shall be tested for integrity by the nitrogen-interface method before it may be returned to storage service.

(3) Storage wellhead and casing. Storage wellhead components and casing shall be inspected at least once every 15 years for corrosion, cracks, deformations, or other conditions that may compromise integrity and that may not be detected by the five-year test. The operator may request an extension of up to five years from the Commission for good cause. Factors the Commission may consider in determining good cause pursuant to this paragraph include by are not limited to the age, location, and configuration of the well; well and facility history; operator compliance record; operator efforts to comply with this subsection; and accuracy of inventory control.

(4) Fresh water, brine, and gas surface piping. Within one year of the effective date of this section, the operator shall submit a piping integrity management plan for approval by the Commission or its designee. Within three years of the effective date of this section, or in conjunction with the storage well integrity testing, all gas, freshwater, and brine surface piping shall be maintained according to the facility's piping integrity management plan.

(p) Plugging.

(1) Plug on abandonment. A gas storage well shall be plugged upon permanent abandonment in a manner approved by the Commission or its designee. A proposal for plugging shall be submitted to the Commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file notification of intent to plug at least five days prior to commencement of plugging operations. A plugging report shall be filed with the Commission within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a gas storage well that has been permanently deactivated, an operator may request approval by the Commission or its designee of a plan to convert the well to a monitor well. A pressure monitoring plan must be submitted to the Commission along with the request to convert the well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in Texas Natural Resources Code, Title 3; Texas Utilities Code, Chapter 121; and other statutes administered by the Commission.

(2) Certificate of compliance. The certificate of compliance for any underground gas storage facility 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.

(r) Applicability of other Commission rules and orders. The owner or operator of an underground gas storage facility is not relieved by this section of compliance with any other requirement of Chapters 3, 4, 7, or 8 of this title (relating to Oil and Gas Division; Environmental Protection; Gas Services Division; or Pipeline Safety Regulations).

Source Note: The provisions of this §3.97 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 289; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.98 Standards for Management of Hazardous Oil and Gas Waste

(a) Purpose. The purpose of this section is to establish standards for management of hazardous oil and gas waste.

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

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

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

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

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

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

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

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

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

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

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

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph.

(2) Administrator--The administrator of the United States Environmental Protection Agency, or the administrator's designee.

(3) Authorized facility--Either:

(A) an authorized recycling or reclamation facility; or

(B) an authorized treatment, storage, or disposal facility.

(4) Authorized recycling or reclamation facility--A facility permitted in accordance with the requirements of 40 CFR, Parts 270 and 124 or Part 271, if required, at which hazardous waste that is to be recycled or reclaimed is managed and whose owner or operator is subject to regulation under:

(A) 40 CFR, §261.6(c) or an equivalent state program (concerning facilities that recycle recyclable materials); or

(B) 40 CFR, Part 266, Subparts C (concerning recyclable materials used in a manner constituting disposal), F (concerning recyclable materials used for precious metal recovery), or G (concerning spent lead-acid batteries being reclaimed), or an equivalent state program.

(5) Authorized representative--The person responsible for the overall operation of all or any part of a facility or generation site.

(6) Authorized treatment, storage, or disposal facility--A facility at which hazardous waste is treated, stored, or disposed of that:

(A) has received either:

(i) a permit (or interim status) in accordance with the requirements of 40 CFR, Parts 270 and 124 (EPA permit); or

(ii) a permit (or interim status) from a state authorized in accordance with 40 CFR, Part 271; and

(B) is authorized under applicable state or federal law to treat, store, or dispose of that type of hazardous waste. If a hazardous oil and gas waste is destined to a facility in an authorized state that has not yet obtained authorization from the EPA to regulate that particular hazardous waste, then the designated facility must be a facility allowed by the receiving state to accept such waste and the facility must have a permit issued by the EPA to manage that waste.

(7) Centralized Waste Collection Facility or CWCF--A facility that meets the requirements of subsection (m)(3) of this section.

(8) Certification--A statement of professional opinion based upon knowledge and belief.

(9) CFR--Code of Federal Regulations.

(10) CESQG--A conditionally exempt small quantity generator, as described in subsection (f)(1) of this section (relating to generator classification and accumulation time).

(11) Commission--The Railroad Commission of Texas or its designee.

(12) Container--Any portable device in which material is stored, transported, treated, disposed of, or otherwise handled.

(13) Contaminated media--Soil, debris, residues, waste, surface waters, ground waters, or other materials containing hazardous oil and gas waste as a result of a discharge or clean-up of a discharge.

(14) Department of Transportation or DOT--The United States Department of Transportation.

(15) Designated facility--An authorized facility that has been designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section (relating to general manifest requirements).

(16) Discharge or hazardous waste discharge--The accidental or intentional spilling, leaking, pumping, pouring, emitting, emptying, or dumping of hazardous waste into or on any land or water.

(17) Disposal--The discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

(18) Disposal facility--A facility or part of a facility at which hazardous waste is intentionally placed into or on any land or water, and at which waste will remain after closure.

(19) Elementary neutralization unit--A device

consisting of a tank, tank system, container, transport vehicle, or vessel that is used for neutralizing wastes that are hazardous wastes:

(A) only because they exhibit the characteristic of corrosivity under the test referred to in subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes); or

(B) they are identified in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) only because they exhibit the corrosivity characteristic.

(20) Empty container--A container or an inner liner removed from a container that has held any hazardous waste and that meets the requirements of 40 CFR, §261.7(b).

(21) Environmental Protection Agency or EPA--The United States Environmental Protection Agency.

(22) EPA Acknowledgment of Consent--The cable sent to the EPA from the United States Embassy in a receiving country that acknowledges the written consent of the receiving country to accept the hazardous waste and describes the terms and conditions of the receiving country's consent to the shipment.

(23) EPA hazardous waste number--The number assigned by the EPA to each hazardous waste listed in 40 CFR, Part 261, Subpart D, and to each characteristic identified in 40 CFR, Part 261, Subpart C.

(24) EPA identification number or EPA ID Number--The number assigned by the EPA to each hazardous waste generator, transporter, and treatment, storage, or disposal facility.

(25) EPA Form 8700-12--The EPA form that must be completed and delivered to the commission in order to obtain an EPA ID number.

(26) Executive director of the TCEQ--The executive director of the TCEQ or the executive director's designee.

(27) Facility--All contiguous land, including structures, other appurtenances, and improvements on the land, used for recycling, reclaiming, treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations thereof).

(28) Generate--To produce hazardous oil and gas waste or to engage in any activity (such as importing) that first causes a hazardous oil and gas waste to become subject to regulation under this section.

(29) Generation site--

(A) Excluding sites addressed in subparagraphs (B) (relating to pipelines) and (C) (relating to gas plants) of this paragraph, any of the following operational units that are owned or operated by one person and other sites at which hazardous oil and gas waste is generated or where actions first cause a hazardous oil and gas waste to become subject to regulation, including but not limited to:

(i) all oil and gas wells that produce to one set of storage or treatment vessels, such as a tank battery, the storage or treatment vessels, associated flowlines, and related land surface;

(ii) an injection or disposal site, that is not part of a generation site described in subparagraph (A)(i) of this paragraph, its related injection or disposal wells, associated injection lines, and related land surface;

(iii) an offshore platform; or

(iv) any other site, including all structures, appurtenances, or other improvements associated with that site that are geographically contiguous, but which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right-of-way.

(B) In the case of a pipeline system (other than a field flowline or injection line system), an equipment station (such as a pump station, breakout station, or compressor station) or any other location along a pipeline (such as a drip pot, pigging station, or rupture), together with any and all structures, other appurtenances, and improvements:

(i) that are geographically contiguous with or are physically related to an equipment station or other location described in this paragraph, but excluding any pipeline that connects two or more such stations or locations;

(ii) that are owned or operated by one person; and

(iii) at which hazardous oil and gas waste is produced or where actions first cause a hazardous oil and gas waste to become subject to regulation.

(C) A natural gas treatment or processing plant or a natural gas liquids processing plant.

(30) Generator--Any person, by generation site, whose act or process produces hazardous oil and gas waste or whose act first causes a hazardous oil and gas waste to become subject to regulation under this section, or such person's authorized representative.

(31) Geothermal energy and associated resources Geothermal energy and associated resources as defined in Texas Natural Resources Code, §141.003(4).

(32) Hazardous oil and gas waste--Any oil and gas waste determined to be hazardous under the provisions of subsection (e) of this section (relating to hazardous waste determination).

(33) Hazardous oil and gas waste constituent--A hazardous waste constituent of hazardous oil and gas waste.

(34) Hazardous waste--A hazardous waste, as defined in 40 CFR, §261.3, including a hazardous oil and gas waste.

(35) Hazardous waste constituent--A constituent that caused the administrator to list a hazardous waste in 40 CFR, Part 261, Subpart D, or a constituent listed in table 1 of 40 CFR, §261.24.

(36) International shipment--The transportation of hazardous oil and gas waste into or out of the jurisdiction of the United States.

(37) Land disposal--The placement in or on the land, except as otherwise provided in 40 CFR, Part 268, including placement in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave, or placement in a concrete vault or bunker intended for disposal purposes.

(38) LQG--A large quantity generator, as described in subsection (f)(3) of this section (relating to generator classification and accumulation time).

(39) Management--The systematic control of the collection, source separation, storage, transportation, processing, treatment, recovery, and disposal of hazardous waste.

(40) Manifest--The shipping document required pursuant to the provisions of subsection (o) of this section (relating to manifests).

(41) Manifest document number--The 12-digit identification number assigned to a generator by the EPA, plus a unique five-digit document number assigned to the manifest by the generator, or preprinted on the manifest, for recording and reporting purposes.

(42) Oil and gas waste--Waste generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, or the solution mining of brine. Until delegation of authority under RCRA to the commission by EPA, the term "oil and gas waste" shall exclude hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants and reservoir pressure maintenance or repressurizing plants.

(43) On-site--At the generation site.

(44) Operator--The person responsible for the overall operation of a facility.

(45) Owner--The person who owns a facility or part of a facility.

(46) P-5 operator number--The number assigned by the commission to each person who conducts any of the activities specified in §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) within the State of Texas.

(47) Person--An individual, firm, joint stock company, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

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

(49) Primary exporter--Any person who is required to originate the manifest for a shipment of hazardous waste in accordance with 40 CFR, Part 262, Subpart B, or equivalent state provision, that identifies a treatment, storage, or disposal facility in a receiving country as the facility to which the hazardous waste will be sent and any intermediary arranging for the export.

(50) Receiving country--A foreign country to which a hazardous waste is sent for the purpose of treatment, storage, or disposal (except short-term storage incidental to transportation).

(51) Reclaim--To process to recover a usable product or to regenerate.

(52) Recycle--To beneficially use, reuse, or reclaim hazardous waste.

(53) Reportable quantity--The quantity of a hazardous substance released in a 24-hour period that must be reported under the provisions of 40 CFR, Part 117 (for spills to water) or Part 302 (any spill).

(54) Resource Conservation and Recovery Act or RCRA--The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended, 42 USC §6901, et seq.

(55) Reuse--To employ hazardous waste as an ingredient in an industrial process to make a product (other than recovery of distinct components of hazardous waste as separate end products) or effective substitution of hazardous waste for a commercial product used in a particular function or application.

(56) Sludge--Any solid, semi-solid, or liquid waste generated from a wastewater treatment plant or water supply treatment plant, or air pollution control facility, exclusive of the treated effluent from a wastewater treatment plant.

(57) Solid waste--Any waste identified in 40 CFR, §261.2.

(58) Solution mined brine--Brine extracted from a subsurface salt formation through dissolution of salt in the formation.

(59) SQG--A small quantity generator, as described in subsection (f)(2) of this section (relating to generator classification and accumulation time).

(60) State--Any of the 50 states that compose the United States, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands.

(61) Storage--The holding of hazardous waste for a temporary period (excluding storage at the site of generation during the applicable accumulation time period specified in subsection (f) of this section), at the end of which the hazardous waste is recycled, reclaimed, treated, disposed of, or stored elsewhere.

(62) Tank--A stationary device designed to contain an accumulation of hazardous waste that is constructed primarily of non-earthen materials (e. g., wood, concrete, steel, plastic) that provide structural support.

(63) Tank system--A tank and its associated ancillary equipment and containment system.

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

(65) Totally enclosed treatment facility--A facility for the treatment of hazardous waste that is directly connected to an industrial production process and that is constructed and operated in a manner that prevents the release of any hazardous waste or hazardous waste constituent into the environment during treatment (e.g., a pipe in which waste acid is neutralized).

(66) Transfer facility--Any transportation-related facility including loading docks, parking areas, storage areas, and other similar areas where shipments of hazardous waste are held during the normal course of transportation.

(67) Transport vehicle--A motor vehicle or rail car used for the transportation of cargo. Each cargo-carrying body (trailer, railroad freight car, etc.) is a separate transport vehicle.

(68) Transportation--The movement of hazardous waste by air, rail, highway, or water.

(69) Transporter--A person engaged in the off-site transportation of hazardous waste.

(70) Treatment--Any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of any hazardous waste so as to neutralize such waste, to recover energy or material resources from the waste, or to render such waste non-hazardous or less hazardous, safer to transport, store, or dispose of, amenable for recovery or storage, or reduced in volume. The term does not include any activity that might otherwise be considered treatment that is exempt from regulation under this section (such as neutralization of caustic or acidic fluids in an elementary neutralization unit).

(71) TCEQ-Form 0311--The TCEQ Uniform Hazardous Waste Manifest form. This form can be obtained from the commission.

(72) United States--The 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

(73) Used Oil--Any oil that has been refined from crude oil, or any synthetic oil, that has been used and as a result of such use is contaminated by physical or chemical impurities.

(74) Vessel--Every description of watercraft used or capable of being used as a means of transportation on the water. The term does not include a structure that is or is designed to be, permanently affixed to one location, or a drilling or workover vessel that is stationary or fixed for the performance of its primary function.

(75) Waste--Any solid waste, as that term is defined in 40 CFR, §261.2.

(76) Wastewater treatment unit--A device (such as a hydrostatic test water treatment unit) that:

(A) is a tank or tank system comprising part of a wastewater treatment facility that is subject to regulation under either §§402 or 307(b) of the Clean Water Act, 33 USC §§1342 or 1317(b); and

(B) receives and treats or stores an influent wastewater that is a hazardous waste, that generates and accumulates a wastewater treatment sludge that is a hazardous waste, or treats or stores a wastewater treatment sludge that is a hazardous waste.

(77) Water (bulk shipment)--The bulk transportation of hazardous waste that is loaded or carried on board a vessel without containers or labels.

(c) Applicability.

(1) General.

(A) This section applies to any person who generates hazardous oil and gas waste and to any person who transports hazardous oil and gas waste.

(B) An owner or operator of a treatment, storage, or disposal facility regulated by the TCEQ's industrial and hazardous waste program, shall be subject to the standards for generators of hazardous waste found in Title 30, Texas

Administrative Code, Chapter 335, Subchapter C (TCEQ standards for generators) if the facility generates a new waste that contains hazardous oil and gas waste and waste regulated by the TCEQ's industrial and hazardous waste program.

(2) Requirements Cumulative. The provisions of this section are in addition to applicable provisions contained in any other section, order, policy, rule, or statutory authority of the commission. In the event of a conflict between this section and any other section, order, policy, or rule of the commission, this section shall control.

(d) General Prohibitions. No person may cause, suffer, allow, or permit the collection, handling, storage, transportation, treatment, or disposal of hazardous oil and gas waste in a manner that would violate the provisions of this section.

(e) Hazardous Waste Determination.

(1) Determination. A person who generates a waste shall determine if such waste is hazardous oil and gas waste as provided in this subsection. A hazardous oil and gas waste is a waste that:

(A) is defined in subsection (b) of this section (relating to definitions) as an oil and gas waste;

(B) is not described in 40 CFR, §261.4(a) (which describes wastes that are not considered solid wastes);

(C) is not described in 40 CFR, §261.4(b) (which describes solid wastes that are exempt from regulation under RCRA Subtitle C); and

(D) is identified as a hazardous waste either:

(i) in 40 CFR, Part 261, Subpart D (regarding listed hazardous wastes); or

(ii) in 40 CFR, Part 261, Subpart C (regarding characteristically hazardous wastes), as determined either:

(I) by testing the waste:

(-a-) in accordance with methods described in 40 CFR, Part 261, Subpart C; or

(-b-) in accordance with an equivalent method approved by the administrator under 40 CFR, §260.21; or

(II) by applying knowledge of the hazard characteristics of the waste in light of the materials or processes used.

(2) Land Ban. Each LQG and SQG shall determine whether the hazardous oil and gas waste it generates is prohibited from land disposal under the provisions of 40 CFR, Part 268. If the waste is prohibited from land disposal, the LQG or SQG must comply with all applicable provisions of 40 CFR, Part 268 (concerning management of land ban wastes) prior to disposing of such waste.

(3) Exclusions and Exemptions.

(A) Notwithstanding the provisions of subsection (e)(1) of this section, in the event the administrator determines, in accordance with the provisions of 40 CFR, §260.22, that a particular oil and gas waste that is considered a hazardous oil and gas waste because it meets criteria set out in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) should not be considered a hazardous waste, such waste shall be exempt from regulation under this section.

(B) Notwithstanding the provisions of subsection (e)(1) of this section the following are exempt from regulation under this section:

(i) any oil and gas waste described in 40 CFR, §261.6(a)(2) (concerning recyclable materials) that is managed as provided in applicable provisions of 40 CFR, Part 266, Subparts C - H, and 40 CFR, Parts 270 and 124;

(ii) any oil and gas waste described and recycled, reclaimed, or reused as provided in 40 CFR, §261.6(a)(3) (concerning recyclable materials);

(iii) used oil that is not considered a hazardous waste under the provisions of 40 CFR, §279.10(b) and that is managed as provided in 40 CFR, Part 279;

(iv) dielectric fluid containing polychlorinated biphenyls (PCBs) and electric equipment containing such fluid that are regulated under 40 CFR, Part 761 and that are hazardous only because they exhibit the characteristic of toxicity for D018-D043 under the test required under subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes);

(v) debris, as that term is defined in 40 CFR, §268.2, that is an oil and gas waste:

(I) that contains or contained a hazardous oil and gas waste listed in 40 CFR, Part 261, Subpart D or that exhibits or exhibited a hazardous waste characteristic identified in 40 CFR, Part 261, Subpart C; and

(II) that has been treated using one of the required destruction technologies specified in Table 1 of 40 CFR, §268.45 or that is determined by the administrator to be no longer contaminated with hazardous oil and gas waste; and

(vi) hazardous oil and gas waste remaining in an empty container.

(f) Generator Classification and Accumulation Time.

(1) Conditionally Exempt Small Quantity Generator.

(A) To be classified as a conditionally exempt small quantity generator (CESQG) during any calendar month, a generator of hazardous oil and gas waste must:

(i) generate no more than 100 kilograms (220.46 pounds) of hazardous oil and gas waste in that calendar month; and

(ii) accumulate no more than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) Except as provided in subsection (f)(5) of this section, a CESQG must comply with all requirements of this section applicable to CESQGs.

(C) If a CESQG generates in one calendar month, or accumulates on-site at any one time, more than a total of one kilogram (2.20 pounds) of any acute hazardous waste listed in 40 CFR, §261.31, 261.32 or 261.33(e) or a total of 100 kilograms (220.46 pounds) of contaminated media resulting from the clean up of a discharge into or on any land or water of any acute hazardous waste listed in 40 CFR, §261.31, 261.32, or 261.33(e), all such acute hazardous wastes must be managed as though generated by an LQG. The LQG accumulation time period for such acute hazardous wastes shall begin at such time as the maximum quantity specified in this subparagraph is exceeded.

(2) Small Quantity Generator.

(A) To be classified as a small quantity generator (SQG) in any calendar month, a generator of hazardous oil and gas waste must:

(i) generate less than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste in that calendar month;

(ii) not allow any particular quantity of hazardous oil and gas waste to remain on-site for a period of more than:

(I) 180 days from the date that particular quantity was generated; or

(II) 270 days from the date that particular quantity was generated, but only if the waste must be transported or offered for transport to a treatment, storage, or disposal facility that is located a distance of 200 miles or more from the point of generation; and

(iii) not accumulate more than 6,000 kilograms (13,227.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) An SQG must accumulate all hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all requirements of this section applicable to SQGs.

(C) The accumulation period specified in subsection (f)(2)(A)(ii) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for a longer time period.

(3) Large Quantity Generators.

(A) Any generator of hazardous oil and gas waste not classified as a CESQG or SQG is classified as a large quantity generator (LQG).

(B) An LQG must accumulate hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all other requirements of this section applicable to LQGs.

(C) An LQG shall not accumulate any particular quantity of hazardous oil and gas waste on-site for more than 90 days from the date that particular quantity was generated, unless an extension to such 90-day period has been granted in accordance with the provisions of subsection (f)(4)(D) of this section.

(D) The 90-day accumulation period specified in subsection (f)(4)(C) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for longer than 90 days.

(4) Accumulation in Containers at the Point of Generation.

(A) Notwithstanding the foregoing provisions of subsection (f) of this section, an LQG or SQG may accumulate in containers up to 55 gallons of hazardous oil and gas waste or a total of one quart of acute hazardous wastes listed in 40 CFR, §261.33(e) without having to manage such hazardous oil and gas waste in accordance with the accumulation time limits applicable to LQGs or SQGs or with the provisions of subsections (q) (relating to preparedness and prevention), (r) (relating to contingency plan and emergency procedures), (s) (relating to personnel training), (t) (relating to standards for use of containers), and (u) (standards for use of tank systems) of this section, provided that the requirements of subsection (f)(4)(B) of this section are met.

(B) All hazardous oil and gas waste subject to the exemption of subsection (f)(4)(A) of this section must be accumulated in containers that:

(i) are at a location that is:

(I) under the control of the generator; and

(II) at or near the point of generation;

(ii) meet the applicable requirements of 40 CFR,

§§265.171, 265.172, and 265.173(a) (concerning container condition, compatibility of waste with container, and closing containers); and

(iii) are marked with the words "Hazardous Waste" or with other words that identify the contents of the containers.

(C) If the amount of hazardous waste accumulated on-site at or near the point of generation exceeds the maximum amount specified in subsection (f)(4)(A) of this section, the generator must, with respect to such excess waste, comply with all applicable provisions of this section within three days of the date that such maximum amount is exceeded.

(5) Episodic Generation. Except as otherwise provided in this paragraph, if a generator's classification varies from one month to another, the hazardous oil and gas waste generated during any particular month shall be managed in accordance with the requirements applicable to the generator's classification for that month.

(A) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(B) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an SQG, the mixture shall be managed in accordance with the standards applicable to SQGs.

(C) If hazardous oil and gas waste generated by a generator who is classified as an SQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(g) Notification. A person who is considered an LQG or SQG under the provisions of this section must notify the commission of the activities of such person that are subject to the provisions of this section and obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission. Such notification must be made upon the later of 90 days after the effective date of this section or within ten days of the date that the LQG or SQG becomes subject to the provisions of this section.

(h) Preparedness and Prevention.

(1) General. In addition to all other applicable requirements of this section, all generators of hazardous oil and gas waste shall employ reasonable and appropriate measures (considering the nature and location of the facility and the types and quantities of hazardous oil and gas waste maintained at the site) in the operation and maintenance of his or her generation site to minimize the possibility of a fire, explosion, or any unplanned sudden or non-sudden release of hazardous oil and gas wastes or hazardous oil and gas waste constituents to air, soil, or surface water that could threaten human health or the environment.

(2) LQGs and SQGs. LQGs and SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart C (concerning preparedness and prevention).

(i) Contingency Plan and Emergency Procedures.

(1) LQGs. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart D (concerning contingency plan and emergency procedures).

(2) SQGs. SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions of 40 CFR, §262.34(d)(5) (concerning emergency response).

(j) Personnel Training. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, §265.16 (concerning personnel training).

(k) Standards for Use of Containers.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I (concerning use and management of containers);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I, except §265.176 (concerning distance from property lines);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(3) CESQGs. The provisions of this paragraph apply to CESQGs only.

(A) Hazardous oil and gas waste generated by a CESQG may be mixed with non-hazardous waste even though the resultant mixture exceeds the quantity limitations of subsection (f)(1) of this section, unless the mixture exhibits any of the hazardous waste characteristics of the hazardous oil and gas waste in the mixture, as determined under subsection (e)(1)(D)(ii) of this section.

(B) If a CESQG's wastes are mixed with used oil, the mixture is subject to the requirements 40 CFR, Part 279 if the mixture is destined to be burned for energy recovery. Any material produced from such a mixture by processing, blending, or other treatment is also so regulated if it is destined to be burned for energy recovery.

(l) Standards for Use of Tank Systems.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart J, except §265.197(c) and §265.200;

(B) comply with the provisions applicable to owners or operators of 40 CFR, §265.111 and §265.114 (concerning closure performance standards and disposal of contaminated equipment and media); and

(C) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions of 40 CFR, §265.201 (concerning accumulation of waste in tanks by small quantity generators); and

(B) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(m) Disposition of Hazardous Oil and Gas Waste.

(1) On-site Treatment, Storage, Disposal, Recycling, and Reclamation. Except as otherwise specifically provided in this section, no person may treat, store, dispose of, recycle, or reclaim any hazardous oil and gas waste on-site.

(2) Transport to Authorized Facility.

(A) Except as otherwise specifically provided in this section and subject to all other applicable requirements of state or federal law, a generator of hazardous oil and gas waste must send his or her waste to one of the following categories of facilities for treatment, storage, disposal, recycling, or reclamation:

(i) an authorized recycling or reclamation facility;

(ii) an authorized treatment, storage, or disposal facility;

(iii) a facility located outside the United States, provided that the requirements of subsection (v)(1) of this section (relating to exports of hazardous waste) are met;

(iv) a transfer facility, provided that the requirements of subsection (w)(3) of this section are met;

(v) if the waste is generated by a CESQG, a facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste; or

(vi) if the waste is generated by a CESQG, a centralized waste collection facility (CWCF) that meets the requirements of subsection (m)(3) of this section.

(B) Notwithstanding any contrary provision of this subsection, hazardous oil and gas wastes may be treated or stored on-site in an elementary neutralization unit or a totally enclosed treatment facility. If a hazardous oil and gas waste that is ignitable under 40 CFR, §261.21 (other than DOO1 High TOC Subcategory wastes defined in 40 CFR, §268.42, Table 2) or that is corrosive under 40 CFR, §261.22 is being treated in an elementary neutralization unit or a wastewater treatment unit to remove the characteristic before land disposal, the owner or operator must comply with the requirements of 40 CFR, §264.17(b).

(C) While waste is being accumulated on-site in accordance with the provisions of subsection (f) of this section, a generator may treat hazardous oil and gas waste on-site in tanks or containers that comply with the applicable provisions of subsections (k) and (l) of this section.

(D) For purposes of §3.8(f)(1)(C)(vi) of this title (relating to Water Protection), the manifest for shipment of hazardous oil and gas waste to a designated facility (a facility designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section) shall be deemed commission authorization for disposal at a facility permitted by another agency or another state.

(3) Centralized Collection of Hazardous Oil and Gas Waste.

(A) Centralized Waste Collection Facility. Provided that the requirements of this paragraph are met, a person may maintain at a CWCF hazardous oil and gas waste that

is generated:

(i) by that person; and

(ii) at sites where that person is considered a CESQG under the provisions of this section.

(B) Prior to receipt of oil and gas hazardous waste generated off-site, a person who operates a CWCF must register with the commission by filing with the commission a notice that includes the following information:

(i) a map showing the location of the CWCF and each individual hazardous oil and gas waste generation site that may contribute waste to the collection facility. In lieu a map, the person who operates the CWCF may provide to the commission the name and lease number, field name and number, or other identifying information acceptable to the commission, of the CWCF and each generation site that may contribute waste to the collection facility;

(ii) the person's P-5 operator number; and

(iii) the EPA ID number for the CWCF, if any.

(C) All hazardous oil and gas waste received at the CWCF must be kept in closed containers that are marked with the words "Hazardous Waste."

(D) A person operating a CWCF shall not maintain at the CWCF at any one time more than 5,000 kilograms of hazardous oil and gas waste or more than five quarts of any hazardous oil and gas waste that is listed in 40 CFR, §261.33(e) (acute hazardous waste).

(n) EPA ID Numbers.

(1) Generators. No LQG or SQG may transport or offer for transportation any hazardous oil and gas waste until such generator has obtained an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission.

(2) Transporters. No LQG or SQG may allow his or her hazardous oil and gas waste to be transported by a transporter that does not have an EPA ID number.

(3) Treatment, Storage, or Disposal Facilities. Except in the case of facilities specified in subsection (m)(2)(A)(iii), (vi), and (v) of this section, no LQG or SQG may send his or her hazardous oil and gas waste to a treatment, storage, or disposal facility unless that facility:

(A) is a designated facility as defined in this section; and

(B) has an EPA ID number.

(o) Manifests.

(1) General Requirements.

(A) Except as provided in subsection (o)(1)(E) of this section, each time an LQG or SQG transports hazardous oil and gas waste or offers hazardous oil and gas waste for transportation to an authorized facility, such generator must prepare a manifest form. If the waste was generated in the State of Texas and is being transferred to an authorized facility located within the State of Texas, the generator shall use the form prescribed by the TCEQ. If the authorized facility is located outside the State of Texas, the generator must refer to subsection (o)(2) of this section to determine which manifest form to use.

(B) The generator must specify on the manifest one authorized facility to handle the hazardous oil and gas waste described on the manifest (the "primary designated facility").

(C) The generator may also specify on the manifest one alternate authorized facility to handle the hazardous oil and gas waste (the "alternate designated facility") in the event an emergency prevents delivery of the hazardous oil and gas waste to the primary designated facility.

(D) If the transporter is unable to deliver the hazardous oil and gas waste to the primary designated facility or the alternate designated facility, the generator must either specify another authorized facility to which the hazardous oil and gas waste can be delivered or instruct the transporter to return the hazardous oil and gas waste to the generator. If the generator specifies another authorized facility to which the hazardous oil and gas waste can be delivered, the generator shall instruct the transporter to revise the manifest to show this facility as the designated facility (see subsection (w)(6) of this section relating to transporter's inability to deliver waste).

(E) An SQG is not required to comply with the provisions of this subsection (relating to manifests) if:

(i) the SQG's hazardous oil and gas waste is reclaimed under a contractual agreement (the "hazardous waste reclamation agreement") pursuant to which:

(I) the type of hazardous oil and gas waste and frequency of shipments are specified in the agreement; and

(II) the vehicle used to transport the hazardous oil and gas waste to the hazardous waste reclamation facility and to deliver regenerated material back to the generator is owned and operated by the hazardous waste reclamation facility;

(ii) the SQG maintains a copy of the hazardous waste reclamation agreement in his or her files for a period of at least three years after termination or expiration of the reclamation agreement; and

(iii) the SQG complies with the provisions of 40 CFR, §268.7(a)(10) (concerning land ban wastes subject to tolling agreements) if the waste is determined to be prohibited from land disposal under subsection (e)(2) of

this section (relating to land ban wastes).

(2) Manifests Required for Out-of-State Domestic Shipments.

(A) If the hazardous oil and gas waste was generated within the United States, but outside the State of Texas, and is being transported to an authorized facility located within the State of Texas, the generator must use the form prescribed by the TCEQ.

(B) If the hazardous oil and gas waste was generated within the State of Texas and is being transported to an authorized facility located within the United States but outside the State of Texas (the "consignment state"), the manifest specified by the consignment state shall be used. If the consignment state does not specify a particular manifest form for use, then the generator shall use the form prescribed by the TCEQ.

(3) Number of Copies. The manifest must consist of at least the number of copies that will provide the generator, each transporter, and the owner or operator of the designated facility with one copy each for their records and one additional copy to be returned to the generator by the owner or operator of the designated facility to which the waste was delivered (in accordance with the provisions of 40 CFR, §264.71 and §265.71, or state equivalent).

(4) Use of the Manifest.

(A) The generator must:

(i) sign the manifest certification by hand;

(ii) obtain the handwritten signature of the initial transporter and date of acceptance of the shipment by the initial transporter on the manifest;

(iii) retain one copy of the manifest signed by the initial transporter until the copy signed by the operator of the designated facility (in accordance with 40 Code of Federal Regulations §264.71, §265.71, or state equivalent) is received;

(iv) give the transporter the remaining copies of the manifest; and

(v) obtain one copy of the manifest, signed by the owner or operator of the designated facility that received the hazardous oil and gas waste, and retain that copy for three years from the date the hazardous oil and gas waste was accepted for shipment by the initial transporter.

(B) For shipments of hazardous oil and gas waste within the United States solely by water (bulk shipments only), the generator must send three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to either:

(i) the owner or operator of the designated facility; or

(ii) if exported by water, the last water transporter expected to handle the hazardous oil and gas waste in the United States. Copies of the manifest are not required for each transporter.

(C) For rail shipments of hazardous oil and gas waste within the United States that originate at the generation site, the generator must send at least three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to:

(i) the next non-rail transporter, if any;

(ii) the designated facility, if transported solely by rail; or

(iii) if exported by rail, the last rail transporter expected to handle the hazardous oil and gas waste in the United States.

(D) For shipments of hazardous oil and gas waste to a designated facility located outside the State of Texas and in an authorized state that has not yet obtained authorization from the EPA to regulate that particular waste as hazardous, the generator must determine that the owner or operator of the designated facility agrees to sign and return the manifest to the generator (in accordance with the applicable provisions of 40 CFR, §264.71 or §265.71), and that any out-of-state transporter agrees to comply with the applicable requirements of subsection (w)(4) of this section (relating to manifest requirements for transporters).

(p) Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, an LQG or SQG must package the hazardous oil and gas waste in accordance with the applicable DOT packaging regulations set out in 49 CFR, Parts 173, 178, and 179.

(q) Labeling. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must label each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(r) Marking.

(1) General. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must mark each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(2) Non-Bulk Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must

mark each package that contains hazardous oil and gas waste and is of a size specified in 40 CFR, §262.32(b) (110 gallons or less), with the following words and information. Such words and information must be displayed in accordance with the applicable requirements of 49 CFR, 172.304. The generator must include his or her name and address and the manifest document number in the appropriate space: HAZARDOUS WASTE--Federal Law Prohibits Improper Disposal. If found, contact the nearest police or public safety authority or the U.S. Environmental Protection Agency. Generator's Name and Address: _____ Manifest Document Number: _____

(s) Placarding. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must placard the vehicle or vehicles used to transport such hazardous oil and gas waste, or offer to the initial transporter the appropriate placards. Appropriate placards shall be determined according to DOT regulations set out in 49 CFR, Part 172, Subpart F.

(t) Recordkeeping.

(1) Waste Determination. Each LQG and SQG shall keep records of any and all test results, waste analyses, or other determinations made in accordance with subsection (e) of this section (relating to hazardous waste determination), for at least three years from the date that the waste was last sent to an authorized facility.

(2) Annual Reports. A copy of all reports required in subsection (u)(1) of this section (relating to annual reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(3) Exception Reports. A copy of all reports required under subsection (u)(2) of this section (relating to exception reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(4) Inspection Reports. A copy of each inspection report required under this section shall be retained by the generator for a period of at least three years from the due date of the report.

(5) Extension. The periods of record retention specified in subsection (t)(1) - (4) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(u) Reporting.

(1) Annual Reports. Any generator who is classified as an LQG or SQG during any calendar month of a calendar year shall prepare and submit a single copy of an annual report to the commission on the annual reporting form prescribed by the commission, Form H-21. The report shall be filed on or before the first day of March of the following calendar year and shall be accompanied by the fee assessed under the provisions of subsection (z) of this section. The annual report shall contain a certification signed by the generator. The annual report shall cover activities occurring at the generation site during the month(s) of the reporting year that the site was classified as a small or large quantity generation site, and shall include the following information:

(A) the name of the generator followed by the generator's P-5 operator number in parentheses, the EPA ID number for the generation site, and the address of the generation site or other site-identifying information (such as the lease number, unit number, or T-4 number (in the case of pipelines));

(B) the calendar year covered by the report;

(C) the name, EPA ID number, if any, and address for each authorized facility within the United States to which hazardous oil and gas waste was shipped during the year;

(D) the name and EPA ID number of each transporter used during the year for shipments to an authorized facility within the United States;

(E) a description, EPA hazardous waste number (from 40 CFR, Part 261, Subpart C or D), United States DOT hazard class, and quantity of each hazardous oil and gas waste shipped to an authorized facility within the United States. This information must be listed by the EPA ID number of each facility to which hazardous oil and gas waste was shipped. If the waste was shipped to an authorized facility that does not have an EPA ID number, the type of facility (reclamation or recycling) must be designated on the report;

(F) a description of the efforts undertaken during the year to reduce the volume and toxicity of hazardous oil and gas waste generated; and

(G) a description of the changes in volume and toxicity of hazardous oil and gas waste actually achieved during the year in comparison to previous years, to the extent such information is available.

(2) Exception Reports.

(A) An LQG who does not receive a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 35 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment must contact the transporter and, if necessary, the owner or operator of the designated facility to determine the status of the hazardous oil and gas waste shipment.

(B) An LQG must submit an exception report to the commission if he or she has not received a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 45 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment. The exception report must

include:

(i) a legible copy of the manifest for that shipment of hazardous oil and gas waste for which the generator does not have confirmation of delivery; and

(ii) a letter signed by the generator explaining the efforts taken to locate the hazardous oil and gas waste and the results of those efforts.

(C) An SQG who does not receive confirmation of delivery of hazardous oil and gas waste by receipt of a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 60 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment, must submit to the commission an exception report. The exception report must include:

(i) a legible copy of the manifest for which the generator does not have confirmation of delivery; and

(ii) a notation, either typed or handwritten, indicating that the generator has not received confirmation of delivery of the shipment to the designated facility.

(D) In the case of interstate shipments of hazardous oil and gas waste for which a manifest has not been returned within 45 days of acceptance of the hazardous oil and gas waste for shipment by the initial transporter, an LQG or SQG shall notify the appropriate regulatory agency of the state in which the designated facility is located, and the appropriate regulatory agency of each state in which the shipment may have been delivered, that the manifest has not been received. If a state required to be notified under this section has not received interim or final authorization pursuant to the RCRA, the LQG or SQG shall notify the administrator that the manifest has not been returned.

(3) Additional Reporting. The commission may require any generator of hazardous oil and gas waste to furnish additional reports concerning the quantities and disposition of hazardous oil and gas waste generated.

(v) Additional Requirements Applicable to International Shipments.

(1) Exports.

(A) Any person who exports hazardous oil and gas waste to a foreign country must comply with the requirements of 40 CFR, Part 262, Subpart E.

(B) Primary exporters of hazardous oil and gas waste generated within the State of Texas must submit to the commission a copy of the annual report submitted to the administrator in compliance with 40 CFR, §262.56.

(2) Imports. Any person who imports hazardous oil and gas waste generated outside the United States into the State of Texas shall be considered the generator of such hazardous oil and gas waste for the purposes of this section. Such person must comply with the applicable provisions of this section, except that:

(A) the name and address of the foreign generator and the importer's name, address, and EPA ID number shall be substituted on the manifest in place of the generator's name, address, and EPA ID number;

(B) the importer or the importer's agent must sign and date the certification and obtain the signature of the initial transporter in place of the generator's certification statement on the manifest; and

(C) the importer shall use the manifest form prescribed by the TCEQ.

(w) Standards Applicable to Transporters of Hazardous Oil and Gas Waste. The following standards apply to persons who transport hazardous oil and gas waste generated by LQGs and SQGs. The requirements of this subsection do not apply in the case of hazardous oil and gas waste generated by CESQGs.

(1) Scope.

(A) This subsection establishes standards for persons transporting hazardous oil and gas waste from the generation site to any designated facility. The provisions of this section do not apply with respect to on-site movements of hazardous oil and gas waste.

(B) In addition to the provisions of this subsection, a transporter must comply with standards applicable to generators of hazardous oil and gas waste if he or she mixes hazardous oil and gas wastes of different DOT shipping descriptions by placing them into a single container. If a transporter mixes a hazardous oil and gas waste with a hazardous waste that is not considered a hazardous oil and gas waste, the transporter must comply with the standards applicable to generators of hazardous wastes found at Title 30, Texas Administrative Code, Chapter 335, Subchapter C (the TCEQ's standards for generators of hazardous waste).

(2) Permits and EPA ID Numbers. No transporter may transport hazardous oil and gas waste unless he or she has an EPA ID number. The transporter may obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the appropriate regulatory entity (either EPA, TCEQ, the commission, or another state).

(3) Transfer Facility Requirements. No transporter may store manifested hazardous oil and gas waste at a transfer facility for any period of time unless:

(A) the hazardous oil and gas waste is packaged in containers that meet the requirements of subsection (p) of this section (relating to packaging); and

(B) the hazardous oil and gas waste is stored at the transfer facility for no longer than ten days.

(4) Manifest Requirements.

(A) A transporter may not accept hazardous oil and gas waste for shipment from a generator unless it is accompanied by a manifest signed in accordance with the provisions of subsection (o)(4) of this section (relating to use of the manifest).

(B) Before transporting hazardous oil and gas waste, the transporter must sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste from the generator. The transporter must return a signed copy of the manifest to the generator before leaving the generation site.

(C) The transporter must ensure that the manifest accompanies the shipment of hazardous oil and gas waste. In the case of exports, the transporter must ensure that a copy of the EPA Acknowledgment of Consent is attached to the manifest.

(D) A transporter may not accept hazardous oil and gas waste for export from a primary exporter or other person if:

(i) the transporter knows that the shipment does not conform to the EPA Acknowledgment of Consent; or

(ii) except in the case of shipments by rail, an EPA Acknowledgment of Consent is not attached to the manifest (or shipping paper in the case of exports by water (bulk shipment)).

(E) A transporter who delivers a hazardous oil and gas waste to another transporter or to the designated facility must:

(i) obtain the date of delivery and the handwritten signature of the other transporter or of the owner or operator of the designated facility on the manifest;

(ii) retain one copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping); and

(iii) give the remaining copies of the manifest to the accepting transporter or owner or operator of the designated facility.

(F) The requirements of subsection (w)(4)(C), (D), (E), and (G) of this section do not apply to water (bulk shipment) transporters if:

(i) the hazardous oil and gas waste is delivered by water (bulk shipment) to the designated facility;

(ii) a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste;

(iii) the delivering transporter obtains the date of delivery and handwritten signature of the owner or operator of the designated facility on either the manifest or the shipping paper;

(iv) the person delivering the hazardous oil and gas waste to the initial water (bulk shipment) transporter obtains the date of delivery and signature of the water (bulk shipment) transporter on the manifest and forwards it to the designated facility; and

(v) a copy of the shipping paper or manifest is retained by each water (bulk shipment) transporter in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping).

(G) For shipments involving rail transportation, the requirements of subsection (w)(4)(C), (D), (E), and (F) of this section do not apply and the following requirements do apply:

(i) when accepting hazardous oil and gas waste from a non-rail transporter, the initial rail transporter must:

(I) sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste;

(II) return a signed copy of the manifest to the non-rail transporter;

(III) forward at least three copies of the manifest to:

(-a-) the next non-rail transporter, if any;

(-b-) the designated facility, if the shipment is delivered to that facility by rail; or

(-c-) the last rail transporter designated to handle the hazardous oil and gas waste in the United States; and

(IV) retain one copy of the manifest and rail shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(ii) rail transporters must ensure that a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste at all times;

(iii) when delivering hazardous oil and gas waste to the designated facility, a rail transporter must:

(I) obtain the date of delivery and handwritten signature of the owner or operator of the designated facility on the manifest or the shipping paper (if the manifest has not been received by the facility); and

(II) retain a copy of the manifest or signed shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(iv) when delivering hazardous oil and gas waste to a non-rail transporter, a rail transporter must:

(I) obtain the date of delivery and the handwritten signature of the next non-rail transporter on the manifest; and

(II) retain a copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(v) before accepting hazardous oil and gas waste from a rail transporter, a non-rail transporter must sign and date the manifest and provide a copy to the rail transporter.

(H) Transporters who transport hazardous oil and gas waste out of the United States must:

(i) indicate on the manifest the date the hazardous oil and gas waste left the United States;

(ii) sign the manifest and retain one copy in accordance with the provisions of subsection (v)(1) of this section;

(iii) return a signed copy of the manifest to the generator; and

(iv) give a copy of the manifest to a United States customs official at the point of departure from the United States.

(I) A transporter accepting hazardous oil and gas waste for shipment from an SQG need not comply with the requirements of subsection (w)(4) and (7) of this section provided that:

(i) the hazardous oil and gas waste is being transported pursuant to a reclamation agreement that meets the requirements of subsection (o)(1)(E) of this section;

(ii) the transporter records, on a log or shipping paper, the following information for each shipment:

(I) the name, address, and EPA ID number of the generator of the hazardous oil and gas waste;

(II) the quantity of hazardous oil and gas waste accepted;

(III) all DOT required shipping information;

(IV) the date the hazardous oil and gas waste is accepted;

(iii) the transporter carries this record when transporting the hazardous oil and gas waste to the reclamation facility; and

(iv) the transporter retains these records for a period of at least three years after termination or expiration of the agreement.

(5) Delivery of Waste. The transporter must deliver the entire quantity of hazardous oil and gas waste accepted from a generator or a transporter to:

(A) the primary designated facility;

(B) the alternate designated facility, if the hazardous oil and gas waste cannot be delivered to the primary designated facility because an emergency prevents delivery;

(C) the next designated transporter; or

(D) for exports, the location designated in the EPA Acknowledgment of Consent.

(6) Inability to Deliver Waste. If the hazardous oil and gas waste cannot be delivered as provided in subsection (w)(5) of this section the transporter must contact the generator for further directions and must revise the manifest according to the generator's instructions.

(7) Recordkeeping.

(A) A transporter of hazardous oil and gas waste must keep a copy of the manifest signed by the generator, himself or herself, and the next transporter or the owner or operator of the designated facility for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(B) For shipments delivered to the designated facility by water (bulk shipment), each water (bulk shipment) transporter must retain a copy of the shipping paper containing all the information required in 40 CFR, §263.20(e)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(C) For shipments of hazardous oil and gas waste by rail within the United States:

(i) the initial rail transporter must keep a copy of the manifest and shipping paper with all the information required in 40 CFR, §263.20(f)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter; and

(ii) the final rail transporter must keep a copy of the signed manifest (or the shipping paper if signed by the designated facility in lieu of the manifest) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(D) A transporter who transports hazardous oil and

gas waste out of the United States must keep, for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter, a copy of the manifest indicating that the hazardous oil and gas waste left the United States.

(E) The periods of retention referred to in subsection (w)(7) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(x) Discharges.

(1) Reporting Requirements.

(A) Commission. A person subject to regulation under this section shall immediately notify the commission upon discovery of any discharge in which a reportable quantity of a hazardous oil and gas waste is discharged. Such notification shall be made by contacting the appropriate commission district office.

(B) Federal. Persons subject to regulation under this section shall comply with applicable reporting requirements of 40 CFR, Parts 117, 263, and 302.

(2) Initial Response.

(A) Immediate Action. Upon discovery of a discharge of hazardous oil and gas waste, the generator or transporter must take appropriate immediate action to protect human health and the environment (e.g., notify local authorities, where appropriate, and dike the discharge area).

(B) Permitting Exemption. The prohibition of on-site treatment, storage, disposal, recycling, or reclamation activities in subsection (m)(1) of this section does not apply to activities performed by a person engaged in treatment or containment activities during immediate response to a discharge of hazardous oil and gas waste; an imminent and substantial threat of a discharge of hazardous oil and gas waste; or a discharge of a substance which, when discharged, would become a hazardous oil and gas waste, provided that:

(i) any hazardous oil and gas waste associated with such discharge is managed in accordance with applicable provisions of subsections (h) (relating to preparedness and prevention), (i) (relating to personnel training), (k) (relating to standards for use of containers), and (l) (standards for use of tank systems) of this section; and

(ii) the applicable discharge reporting requirements of subsection (x) of this section are complied with.

(C) Continued Measures. The provisions of subparagraph (B) of this paragraph do not apply to activities that continue or are initiated after the immediate response is over. Such activities are subject to all applicable requirements of this section.

(3) Discharge Clean Up.

(A) The generator or transporter shall recover as much as of the spilled material as can be recovered by ordinary physical means as soon as possible after discovery of the spill.

(B) The generator or transporter shall clean up the site at which the discharge occurred to background levels as soon as reasonably possible. As an alternative to clean-up to background levels, the generator or transporter must take such action as may be required or approved by the commission so that the hazardous oil and gas waste discharge no longer presents a hazard to human health or the environment, taking into consideration the geology and hydrology of the discharge site, the nature and quantity of the hazardous oil and gas waste discharged, and the present and anticipated future use of the discharge site.

(C) If an official (state or local government or a federal agency) acting within the scope of his or her official responsibilities determines that immediate removal of the hazardous oil and gas waste associated with a discharge is necessary to protect human health or the environment, that official may authorize the removal of the hazardous oil and gas waste by transporters who do not have EPA ID numbers and without the preparation of a manifest.

(y) Emergency Permits.

(1) General. Notwithstanding any other provision of this section, the commission may authorize by emergency permit the treatment, storage, or disposal of hazardous oil and gas waste where the commission finds that a discharge of hazardous oil and gas waste poses a danger to life or property.

(2) Requirements. An emergency permit:

(A) may be oral or written. If oral, a written permit must be issued within five days of issuance of the oral permit;

(B) shall have a term of not more than 90 days;

(C) shall clearly specify the manner and location of authorized treatment, storage, and disposal activities;

(D) may be terminated by the commission without notice if the commission determines that termination is appropriate to protect human health and the environment;

(E) shall incorporate, to the extent possible and not inconsistent with the emergency situation, all applicable requirements of 40 CFR, Parts 264, 266, and 270; and

(F) shall be accompanied by a public notice published in a daily or local newspaper of general circulation in the area affected by the activity and broadcast over local radio stations. The notice shall include:

(i) the name and address of the office granting the emergency authorization;

(ii) the name and location at which the permitted activities will take place;

(iii) a brief description of the hazardous oil and gas wastes involved;

(iv) a brief description of the actions authorized and reasons for authorization of such actions; and

(v) the duration of the emergency permit.

(z) Fees.

(1) Base fee.

(A) Except as provided in subparagraph (B) of this paragraph:

(i) each generator who is classified as an LQG during any calendar month of a calendar year shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $1,000;

(ii) each generator who is not classified as an LQG during any calendar month of a calendar year, but is classified as an SQG during a calendar month of that calendar year, shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $200; and

(iii) no annual fee for generation of hazardous oil and gas waste shall be assessed against a generator who is classified as a CESQG during all months of the entire calendar year in which he or she generates hazardous oil and gas waste.

(B) For purposes of determining the base fee as provided in subparagraph (A) of this paragraph, generator classification shall be determined after excluding quantities of hazardous oil and gas waste generated in connection with a spill or discharge, including contaminated soil, media, and debris, if, within 30 days after discovery of such spill or discharge, the generator files a one-page typewritten report with the commission that describes:

(i) the nature and quantity of spilled or discharged material;

(ii) the reason for or cause of the spill or discharge; and

(iii) the steps that have been or will be taken by the generator to minimize the likelihood of a similar spill or discharge at that site.

(2) Additional fee. The base annual fee determined according to the provisions of paragraph (1) of this subsection shall be doubled if less than 50% of the hazardous oil and gas wastes generated at the site during the entire calendar year are recycled, reused or reclaimed. For purposes of calculating the percentage of hazardous oil and gas wastes that are recycled, reused, or reclaimed, hazardous oil and gas wastes excluded from regulation under this section by the provisions of subsection (e)(3)(B)(i) - (iii) of this section (relating to exclusions and exemptions from hazardous oil and gas waste classification) and subsection (m)(2)(B) of this section (relating to elementary neutralization units, totally enclosed treatment facilities, and wastewater treatment units) shall be included in the quantity of hazardous oil and gas waste recycled, reused, or reclaimed. The wastes excluded from regulation under this section under the provisions of subsections (e)(3)(B)(i) - (iii) and (m)(2)(B) of this section shall not be included when calculating the quantity of waste generated for purposes of determining generator classification.

(3) Fee payment. The base fee and any additional fee assessed under this subsection shall be paid to the commission on or before the first day of March of the year following the calendar year in which the waste was generated. Fees assessed under this subsection shall be tendered to the commission with the annual report (see subsection (u)(1) of this section).

(aa) Penalties. A person subject to regulation under this section is subject to the penalties prescribed in the Texas Natural Resources Code if such person does not comply with the requirements of this section.

(bb) Federal Regulations. All references to the Code of Federal Regulations (CFR) in this section are references to the 1994 edition of the Code, as amended through November 7, 1995. The following federal regulations are adopted by reference and copies can be obtained at the William B. Travis Building, 1701 North Congress, Austin, Texas 78711: 40 CFR, Parts 116, 117, 124, 264, 266, 268, 270, 271, 279, and 302; 40 CFR, Part 261, Subparts A, C, and D; 40 CFR, Part 262, Subparts B and E; 40 CFR, Part 265, Subparts C, D, I, and J (except §265.197(c) and §265.200); 40 CFR, §§260.21, 260.22, 262.34(d)(5), 265.16, 265.111, 265.114, and 265.201; 49 CFR, Parts 172, 173, 178, and 179; and 49 CFR, §171.15 and §171.16. Words and terms used in the federal regulations adopted by reference shall have the meanings given in the federal regulations adopted by reference or in 40 CFR, §260.10, unless otherwise specified. Where the term "State Director" is applicable in the federal regulations adopted by reference, it should be interpreted to mean "commission."

Source Note: The provisions of this §3.98 adopted to be effective April 1, 1996, 20 TexReg 9423; amended to be effective May 4, 1999, 24 TexReg 3313; amended to be effective September 10, 2001, 26 TexReg 6870; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.99 Cathodic Protection Wells

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

unless the context clearly indicates otherwise.

(1) Cathodic protection well--Any well drilled for the purpose of installing one or more anodes to prevent corrosion of a facility associated with the production of oil, gas, or geothermal resources, such as a well casing, storage and separation facility, or pipeline.

(2) Project area--The geographic area in which a related group of cathodic protection wells is drilled.

(3) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(4) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any cathodic protection well that is drilled to a depth of 30 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any cathodic protection well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths.

(d) Drilling permits.

(1) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth does not require a drilling permit.

(2) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be drilled in accordance with the requirements of §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Completion.

(1) Timing. A cathodic protection well must be completed as soon as possible after it is drilled.

(2) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(3) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must either set and cement casing to the deepest protection depth penetrated or center a 100-foot cement plug across each protection depth penetrated and must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug cathodic protection wells shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting. Within 30 days of completion of the last well in a project area, the operator shall submit a letter to the commission stating that each cathodic protection well in the project area has been completed in accordance with subsection (e) of this section. The letter must include the completion date for each well, the name and address of the operator, and the drilling permit and API numbers of the well, if applicable. A plat of the project area identifying cathodic protection well locations, counties, survey lines, scale, and northerly direction must be attached. In addition, a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths must be attached.

(h) Abandonment. Upon abandonment of a cathodic protection well, any wires or vent pipe must be cut off at the top of the 10-foot surface plug, and the vent pipe must be securely capped or plugged.

Source Note: The provisions of this §3.99 adopted to be effective July 21, 1992, 17 TexReg 4877; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.100 Seismic Holes and Core Holes

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

(1) Seismic hole--Any hole drilled for the purpose of securing geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources.

(2) Core hole--Any hole drilled for the purpose of securing geological information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal or uranium. For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(3) Project area--The geographic area in which an exploratory survey involving one or more seismic holes or core holes is carried out.

(4) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(5) Operator--The person who contracts for the services of a seismic crew or core hole drilling contractor or, if the seismic survey or core hole testing is not performed on a contract basis, but is performed by an exploration and production company or by a geophysical contractor for speculative purposes, the person who drills the seismic holes or core holes.

(6) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any seismic hole or core hole drilled to a depth of 20 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any seismic hole or core hole in a project area, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths in the project area.

(d) Drilling permits.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth does not require a drilling permit.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth requires a drilling permit to satisfy the requirements for exploratory wells described in §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Plugging.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth must be plugged in accordance with subparagraph (A) or (B) of this paragraph. Seismic holes must be plugged after the hole is loaded with explosives. Core holes must be plugged immediately after completion of coring the hole.

(A) The operator shall adequately plug the hole by filling it from total depth to a depth of no more than 16 feet below the surface with drill cuttings and/or bentonite. Immediately above the drill cuttings and/or bentonite, the operator shall place a bentonite plug no less than 10 feet in length. A plastic cap imprinted with the name of the operator shall be set above the bentonite plug no less than three feet below the surface. The remainder of the hole shall be filled with drill cuttings or native soil. All precautions should be taken to prevent bentonite from bridging over.

(B) Alternative plugging procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth must be plugged in accordance with the requirements of §3.14 of this title (relating to Plugging) (Statewide Rule 14) and a plastic cap imprinted with the name of the operator shall be set in the hole no less than three feet below the surface.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug seismic or core holes shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting.

(1) Holes that do not penetrate any protection depth. Within 30 days of plugging the last hole in the project area, the operator shall submit a letter to the commission stating that each seismic hole or core hole in the project area has been plugged in accordance with subsection (e)(1) of this section. The letter must include the plugging date for each hole and the name and address of the operator. A plat of the project area identifying seismic or core hole locations, counties, survey lines, scale, and northerly direction must be attached. A United States Geological Survey map of the project area with hole locations marked will satisfy the plat requirement. In addition, a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths must be attached.

(2) Holes that penetrate any protection depth. For any seismic or core hole that penetrates any protection depth, a plugging record shall be filed in accordance with §3.14 of this title (relating to Plugging) (Statewide Rule 14).

Source Note: The provisions of this §3.100 adopted to be effective September 1, 1992, 17 TexReg 5283; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.101 Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells

(a) Purpose. This section specifies the procedure by which an operator can obtain a Railroad Commission of Texas certification that natural gas from a particular gas well qualifies as high-cost natural gas under the Texas Tax Code, Chapter 201, Subchapter B, §201.057(a)(2)(A) and that such gas is exempt from or eligible for a reduction of the severance tax imposed by the Texas Tax Code, Chapter 201.

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

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

(2) Completion--The act of making a well capable of producing gas from a particular commission designated or new field.

(3) Completion date--The date on which a well is first made capable of producing oil or gas from a particular commission-designated or new field, as shown on the completion report filed by the operator with the commission.

(4) Comptroller--The Comptroller of Public Accounts of the State of Texas.

(5) Data-point well--A well that has been tested and/or produced in the proposed tight gas formation; and, from the test results or other data, applicant provides a measured or calculated in situ permeability and/or a measured or calculated pre-stimulation stabilized flow rate against atmospheric pressure.

(6) Director--The director of the Oil and Gas Division or the director's delegate. Any authority given to the director in this section is also retained by the commission. Any action taken by the director pursuant to this section is subject to review by the commission.

(7) High-cost gas--Natural gas which the commission finds to be:

(A) produced from any gas well, if production is from a completion which is located at a depth of more than 15,000 feet;

(B) produced from geopressured brine;

(C) occluded natural gas produced from coal seams;

(D) produced from Devonian shale; or

(E) produced from designated tight formations or produced as a result of production enhancement work.

(8) Operator--The person responsible for the actual physical operation of a gas well.

(9) Spud date--The date of commencement of drilling operations, as shown on commission records.

(c) Applicability.

(1) A severance tax exemption is available for high-cost gas produced from a well that is spudded or completed between May 24, 1989, and September 1, 1996. Eligible high-cost gas shall be exempt from the tax imposed by the Texas Tax Code, Chapter 201, during the period from September 1, 1991, through August 31, 2001.

(2) A severance tax reduction is available for high-cost gas produced from a well that is spudded or completed after August 31, 1996. Eligible high-cost gas shall be entitled to a reduction of the tax imposed by the Texas Tax Code, Chapter 201, for the first 120 consecutive calendar months beginning on the first day of production or until the cumulative value of the tax reduction equals 50% of the drilling and completion costs incurred for the well, whichever occurs first. The amount of tax reduction is determined pursuant to the Texas Tax Code, §201.057(c). If the application for certification is submitted to the Commission after January 1, 2004, the total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on the gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 consecutive calendar months immediately preceding the month in which the application for certification under this section was filed with the Commission.

(3) The plug back or deepening of an existing wellbore qualifies as a completion under this section. When the plug back or deepening is completed prior to September 1, 1996, the gas produced may qualify for a tax exemption. When the plug back or deepening is completed after August 31, 1996, the gas produced may qualify for a tax reduction. The plug back or deepening qualifies as a completion if:

(A) it is the initial completion in a commission-designated or newly discovered field that has not been previously produced from that wellbore; or

(B) the operator can demonstrate that the strata between the former completion and the new completion contain a minimum of 20 vertical feet of impermeable strata; or

(C) the operator submits the results of bottom hole pressure surveys, gas analyses or other methods or calculations comparing the new completion with previous completions in the wellbore that were in existence prior to May 24, 1989. The application shall include an explanation of the engineering principles, calculations, and reasoning to show that the gas to be produced from the applied-for completion could not have been produced from any completion in existence prior to May 24, 1989.

(4) If the operator determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the operator takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the operator shall notify the Commission in writing within 30 days after such an event occurs.

(5) If the Commission determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the commission takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the Commission shall notify within 48 hours, in writing, the comptroller and the operator.

(d) Application procedure.

(1) An application for a state severance tax exemption or tax reduction for a gas well may be made only by the operator of that well. The operator shall file one copy of the required application form, one copy of the required attachments specified in subsection (e)(1) - (6) of this section and any additional information deemed necessary by the Commission to clarify, explain and support the required attachments. Submission of legible copies of required attachments shall comply if the application includes a statement, signed by the operator, that the attachments are true and correct copies of the documents originally filed with the Commission. However, the Commission may require an operator to file certified copies of required attachments or other documents from Commission files if necessary for a certification.

(2) Filings and correspondence on high-cost gas state severance tax applications shall be addressed to the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Gas Severance Tax Section. No filings may be made at the district offices.

(e) Application requirements for individual well certifications. To qualify for the severance tax exemption or tax reduction, the operator shall prove that the gas produced is high-cost gas by providing the following information:

(1) Applications for wells producing deep high-cost gas shall include:

(A) the completed applicable commission form; and

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well.

(2) Applications for wells producing geopressured brine shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a bottom-hole pressure test report and other information establishing the initial reservoir pressure gradient; and

(D) evidence to establish that, before production, the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water.

(3) Applications for wells producing coal seam gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well if the gas is produced through a wellbore, or a detailed description of the production process if the gas is not produced through a wellbore;

(C) a radioactivity, electric or other log which will define the coal seams or, if such logs are not reasonably available, a detailed lithologic description of the gas-producing interval; and

(D) evidence to establish that the natural gas was produced from coal seams.

(4) Applications for wells producing Devonian shale gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) an environmentally corrected, calibrated gamma ray log with values greater than 100 API units over the Devonian age stratigraphic section, or a gamma ray log with superimposed indications of the shale base line and the gamma ray index of 0.7 over this section or, if the gamma ray log is not reasonably available, a driller's log or similar report indicating the general characteristics of the strata penetrated and the corresponding depths at which they are encountered throughout the Devonian age stratigraphic section;

(D) information which calculates the percentage of

footage of the producing interval which is not Devonian shale as indicated by the gamma ray log, driller's log, or similar report;

(E) information which demonstrates that the percentage of potentially disqualifying nonshale footage for the stratigraphic section selected is equal to or less than 5.0% of the Devonian stratigraphic age interval; and

(F) reference to a standard stratigraphic chart or text establishing that the producing interval is a shale of Devonian age.

(5) Applications for wells producing designated tight formation gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) specific reference to the commission docket number assigned to the applicable designated tight formation area certification along with a copy of the map with the subject well location shown, which outlines the designated tight formation area approved by the commission.

(6) Applications for wells producing production enhancement gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a description of the production enhancement work that has been performed on the well, including the dates the work was commenced and completed, or that will be performed on the well;

(D) an itemized statement of costs incurred in performing the production enhancement work, including copies of invoices and bills for such work, or, if the work has not yet been completed, estimates of such costs;

(E) a statement estimating, for a five-year test period beginning from the month in which the application is filed, the increase in gas production resulting from the application of production enhancement work;

(F) calculations showing that the projected increase in revenue does not exceed 200% of the §103 price;

(G) the renegotiated price;

(H) a copy of that portion of the sales contract that authorizes collection of the renegotiated price; and

(I) the properly executed statement under oath made by the purchaser of natural gas which states that there is a reasonable basis for the statements and estimates made by the applicant.

(f) Application requirements for tight formation area certifications.

(1) If justification for an individual well application is based on a tight formation certification and the well is not located within a geographical area that has been previously certified as a designated tight formation area or the well is not completed in a formation interval that has been previously certified as a designated tight formation by the Federal Energy Regulatory Commission under the Natural Gas Policy Act or by the Railroad Commission of Texas, the operator shall first apply for a tight formation area designation.

(2) An applicant requesting a tight formation area designation shall submit a written request to the High-Cost Gas Severance Tax Section, at the address given in subsection (d)(2) of this section, for a certification that a named formation or a specific portion thereof is a tight formation. The applicant shall supply a list of the names and addresses of all affected persons. For purposes of this subsection, "affected persons" means all operators of all wells listed on the current proration schedule for the applicable field or fields located within the proposed designated area. The applicant shall mail or deliver a copy of the prescribed, completed notice of application form to all affected persons, and if required, shall publish the notice of application in accordance with §1.46 of this title (relating to Notice by Publication in Oil and Gas and Surface Mining and Reclamation Nonrulemaking Proceedings), as found in the Commission's General Rules of Practice and Procedure (16 Texas Administrative Code Chapter 1). Notice of application forms may be obtained by contacting the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Severance Tax Section. Before the application may be approved, the applicant shall submit a letter certifying that all affected persons were sent a copy of the notice of application, and the date on which the notice of application was sent.

(3) In addition to the written request and list of affected persons, the applicant shall submit the following information in duplicate:

(A) a geographical and geological description of the formation, including:

(i) a map with an outline of the geographical limits of the formation in and around the requested area, with the proposed designated areal boundaries shown, with counties, surveys and abstracts identified and with the locations clearly identified for all wells inside the requested area that have penetrated the proposed formation; all wells (i.e., those that penetrated the proposed formation) shown on the map inside the requested area shall include either the commission's gas well identification number or the API number (if available);

(ii) a list of the counties involved, abstract numbers, survey names, geologic formation markers, and any other descriptive information that will aid in identifying the subject formation including an estimate of the number of acres within the requested area; and

(iii) a structure map contoured on the top of the formation and a cross-section to depict upper and lower limits of the proposed formation, or specific portion thereof.

(B) engineering and geological exhibits, including a written explanation of each, to establish the following:

(i) that the in situ permeability throughout the proposed formation or specific portion thereof is 0.1 millidarcies or less, as determined by geometric mean or median analysis of available data from all wells that either have been tested or are completed in the proposed formation within the requested area. If no in situ permeability estimates are provided for wells that are in the requested area and have been tested and/or are completed in the proposed formation, an explanation shall be provided;

(ii) that the pre-stimulation stabilized production rate against atmospheric pressure at the wellhead, as determined by a geometric mean or median analysis of available data from all wells within the requested area that either have been tested and/or are completed in the proposed formation or specific portion thereof, does not exceed the production rate listed in the following table:

If the average depth to the top of the formation (in feet)		The maximum allowable production rate (in thousand cubic feet per day) may not exceed-
exceeds-	but does not exceed-	
0	1,000	44
1,000	1,500	51
1,500	2,000	59
2,000	2,500	68
2,500	3,000	79
3,000	3,500	91
3,500	4,000	105
4,000	4,500	122
4,500	5,000	141
5,000	5,500	163
5,500	6,000	188
6,000	6,500	217
6,500	7,000	251
7,000	7,500	290
7,500	8,000	336
8,000	8,500	388
8,500	9,000	449
9,000	9,500	519
9,500	10,000	600
10,000	10,500	693
10,500	11,000	802
11,000	11,500	927
11,500	12,000	1,071

12,000	12,500	1,238
12,500	13,000	1,432
13,000	13,500	1,655
13,500	14,000	1,913
14,000	14,500	2,212
14,500		2,557

(iii) that no well drilled into the formation is expected to produce, without stimulation, more than five barrels of crude oil per day; and

(iv) that the requested designated area does not extend beyond a two and one-half mile radius drawn from any data point well.

(g) Commission action on applications for individual well certifications and for tight formation area designations.

(1) Each application, for an individual well certification, shall be assigned a docket number identifying it as a severance tax application. A notice of receipt shall be sent to the applicant, indicating the assigned docket number and receipt date. All further correspondence shall include this docket number.

(2) The director may administratively approve the individual well certification applications if the forms and information submitted by the operator establish that the gas qualifies as high-cost gas eligible for the severance tax exemption or tax reduction. If the director denies administrative approval, the applicant shall have the right to a hearing.

(3) If Commission staff finds that the data submitted with the tight formation area designation applications are complete and comply with the requirements set out in subsection (f)(3) of this section and if no protest to the application is filed within 21 days of the notice, the application shall be presented to the Commission for approval. If Commission staff finds the data submitted are incomplete, or indicate the area does not qualify, or if a protest is filed within the 21-day notice period, the applicant shall request a hearing to have the application considered. If the applicant does not request such a hearing or if the applicant fails to appear at a requested hearing, the application shall be dismissed. Any such hearing shall be held only after at least 10 days' notice by the Commission to all affected persons as defined in subsection (f)(2) of this section. If no protestant appears at the hearing, and/or if the application and any evidence presented at the hearing establishes that the subject formation meets the requirements for a tight formation certification, the application shall be presented to the Commission for approval.

(h) Reporting. To qualify for the exemption or tax reduction provided by Texas Tax Code, §201.057(a)(2)(A), all persons responsible for paying the tax shall apply with the comptroller after receiving a copy of the Commission's certification letter. The application shall contain the Commission's letter certifying that the well produces or will produce high-cost gas, a completed copy of the Commission's application for certification form and a completed copy of the applicable Comptroller of Public Accounts' form. To obtain the maximum tax exemption or tax reduction, the application shall be filed with the comptroller at the later of the 180th day after the first day of production or the 45th day after the certification by the Commission. If the application is not filed by the applicable deadline, the tax exemption or reduction will be reduced by 10% for the period beginning on the 180th day after the first day of production and ending on the date on which the application is filed with the comptroller.

Source Note: The provisions of this §3.101 adopted to be effective January 11, 1995, 19 TexReg 10351; amended to be effective September 15, 1997, 22 TexReg 8974; amended to be effective August 13, 2001, 26 TexReg 6009; amended to be effective October 12, 2003, 28 TexReg 8585.

§3.102 Tax Reduction for Incremental Production

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain a 50% severance tax reduction for five years on the incremental oil and casinghead gas production from a qualifying lease.

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

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number.

(2) Production--Barrels of oil (including barrels of gas liquids reported as production monthly on the appropriate form) plus casinghead gas, where six thousand cubic feet of gas is the equivalent of one barrel of oil, expressed in barrels of oil equivalent (BOE).

(3) Baseline production--An oil lease's average BOE monthly production during the four highest months of production in the time period from January 1, 1996, through December 31, 1996.

(4) Incremental production--Production from a

qualifying lease in excess of baseline production.

(5) Incremental production technique--

(A) any secondary or tertiary production enhancement technique;

(B) any primary production enhancement technique that an operator certifies required an expenditure of at least $5,000 to cause increased production.

(6) Qualifying lease--A lease is a qualifying lease provided that:

(A) the commission has designated the lease as an oil lease and has assigned to it an identifying number;

(B) production from the lease, measured by dividing the sum of lease production during the four-month period used to compute the baseline production by the sum of the number of well-days during the same four-month period, is no more than seven barrels of oil equivalent per day per well, excluding gas flared pursuant to the rules of the commission; and

(C) after the operator performs an incremental production technique, the lease shows incremental production for four of five consecutive months on or after September 1, 1997, and before December 31, 1998.

(7) Incremental ratio--The amount of a qualifying lease's average monthly incremental production during the four-month period used to meet the definition of a qualifying lease divided by its average monthly total production during the same four-month period.

(8) Qualified incremental production--A qualifying lease's total monthly production multiplied by the incremental ratio.

(9) Well-day--One well producing hydrocarbons for one day.

(c) Qualification for the tax reduction. An operator of a qualifying lease is entitled to a 50% tax reduction on that lease's qualified incremental production for five years provided that:

(1) The operator of a qualifying lease applies to the commission for a determination of an incremental ratio before February 11, 1999;

(2) The commission certifies an incremental ratio;

(3) The operator provides to the state comptroller the certified incremental ratio; and

(4) The operator applies to the state comptroller for the tax relief provided by this section not later than one year after the date the commission certifies the incremental ratio for a qualifying lease.

(d) Request for hearing. If the request for certification of an incremental ratio is denied administratively, or if the operator does not agree with the administrative determination of the amount of the incremental ratio, the applicant may request a hearing. The request for a hearing must be filed within 20 days after the date on which notice of the administrative decision is mailed to the operator. The commission shall provide notice of the hearing to the applicant and to any other affected person named by the applicant. After hearing, the examiner shall recommend final action by the commission.

Source Note: The provisions of this §3.102 adopted to be effective June 23, 1998, 23 TexReg 6437.

§3.103 Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared

(a) Purpose. The purpose of this section is to provide a procedure by which an operator may obtain commission certification that the operator markets gas that was previously released into the air for 12 months or more pursuant to §3.32 of this title (relating to Gas Well Gas and Casinghead Gas Shall Be Used for Legal Purposes). Certification under this section is voluntary.

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

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number as listed on the monthly oil proration schedule at the time an application is filed under this rule.

(2) Oil well--A wellbore completed in a commission-designated field and assigned to an oil lease as listed on the monthly oil proration schedule at the time an application for certification is filed under this rule.

(c) Eligibility. An operator shall be eligible to receive the tax exemption on marketed casinghead gas for the life of an oil well or oil lease as listed on the oil proration schedule at the time an application for certification is filed under this rule if:

(1) the operator previously released the casinghead gas from an oil well or oil lease into the air for 12 months or more pursuant to §3.32 of this title; and

(2) the operator marketed the gas no earlier than June 1, 1997, in accordance with §3.32 of this title.

(d) Certification.

(1) An operator may apply for commission certification on the appropriate form. The completed form shall be accompanied by information necessary to establish:

(A) prior release into the air of casinghead gas for 12 months or more during a period of 13 consecutive months

pursuant to §3.32 of this title; and

(B) such gas has generated taxable proceeds subject to the severance tax as a result of being marketed on or after September 1, 1997.

(2) The director of the commissions's Oil and Gas Division, or the director's delegate, may administratively approve or deny a request for certification.

(3) If the director of the commission's Oil and Gas Division or the director's delegate denies the request, the operator may request a hearing by filing such a request in writing within 15 days after the postmarked date of the notice of the administrative denial.

(4) If the operator fails to appear at the hearing without good cause, the request for certification shall be dismissed.

(5) Filings and correspondence concerning the application for certification shall be addressed to the Railroad Commission, P.O. Box 12967, Austin, Texas 78711-2967, Attention: Permitting/Production Services Section.

(e) Application to the Comptroller. After the commission issues the certification provided for in subsection (d) of this section, the operator may apply to the Comptroller of Public Accounts to receive the tax exemption.

(f) Termination of Authorization to Release Gas. On the date the commission issues the certification provided for in subsection (d) of this section, either by administrative action or by commission order, the volume of casinghead gas authorized to be released into the air as an exception obtained pursuant to §3.32(h) of this title shall be reduced to the volume of casinghead gas not subject to the certification. If all of the volume of casinghead gas authorized to be released under an exception is certified for purposes of the tax exemption, the exception shall no longer apply, and shall automatically terminate as of the date of certification.

Source Note: The provisions of this §3.103 adopted to be effective August 4, 1998, 23 TexReg 7770.

§3.106 Sour Gas Pipeline Facility Construction Permit

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

(1) Affected person--The owner or occupant of real property located in the area of influence of the proposed route of a sour gas pipeline facility. If the final proposed route of the pipeline is unknown at the time of application, then an affected person is any person who owns or occupies real property located within the area of influence associated with any possible pipeline route identified by the applicant. For purposes of this definition, the owner shall be the owner of record as of the final day to protest an application. The occupant shall be the occupant as of the final day to protest an application.

(2) Applicant--A person who has filed an application for a permit to construct a sour gas pipeline facility, or a representative of that person.

(3) Application--Application for a Permit to Construct a Sour Gas Pipeline Facility, and all required attachments.

(4) Area of influence--Area along a sour gas pipeline facility represented by all possible areas of exposure using the 100 ppm radius.

(5) Construction of a facility--Any activity conducted during the initial construction of a pipeline including the removal of earth, vegetation, or obstructions along the proposed pipeline right-of-way. The term does not include:

(A) surveying or acquiring the right-of-way;

(B) clearing the right-of-way with the consent of the owner;

(C) repairing or maintaining an existing sour gas pipeline facility; or

(D) installing valves or meters or other devices or fabrications on an existing pipeline if such devices or fabrication do not result in an increase in the area of influence.

(6) Extension of a sour gas pipeline facility--An addition to an operating sour gas pipeline facility regardless of ownership of the addition.

(7) Nominal pipe size--The industry convention for naming pipe. Six inch nominal size pipe corresponds to pipe with an approximate inner diameter of six inches. The actual inner diameter varies based on the wall thickness of the pipe.

(8) Person--An individual, partnership, firm, corporation, joint venture, trust, association, or any other business entity, a state agency or institution, county, municipality, school district, or other governmental subdivision.

(9) Preliminary contingency plan--A contingency plan containing all of the elements required for a contingency plan under §3.36 of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas), except that:

(A) the plan need not contain the list of names and telephone numbers of residents within the area of influence if required under §3.36(c)(9)(I) of this section. In lieu of this list of names and telephone numbers, the plan shall contain a detailed explanation of the manner in which the names and telephone numbers of residents within the area of influence will be compiled prior to commencement of operations;

(B) the plat detailing the area of influence may be:

(i) the detailed plat required under §3.36(c)(9)(H);

(ii) a plat containing the information required under §3.36(c)(9)(H), that identifies residential, business, and industrial areas with an estimate of the number of people that may be within any such areas; or

(iii) one or more aerial photographs covering the area and providing the information required under §3.36(c)(9)(H); and

(C) a fixed pipeline route need not be specified in the preliminary plan provided the preliminary plan identifies the boundaries of the area within which the pipeline will be constructed and provided that all public notices of the application required under this section note such boundaries and identify the potential area of influence as the total area encompassed by the area of influence associated with all possible pipeline routes.

(10) Sour gas pipeline facility--A pipeline and ancillary equipment that:

(A) contains a concentration of 100 parts per million or more of hydrogen sulfide;

(B) is located outside the tract of production; and

(C) is subject to the requirements of §3.36 of this title.

(11) Tract of production--The surface area which overlies the area encompassed by a mineral lease or unit from which oil, gas, or other minerals are produced if such area is treated by the Oil and Gas Division of the commission as a single tract.

(12) 100 ppm radius--The 100 parts per million radius of exposure as calculated in §3.36(c)(1) - (3) of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas) for the sour gas pipeline facility.

(b) Permit Required; Exceptions. No person may commence construction of a facility within this State without a permit if the facility is initially used as a sour gas pipeline facility except for the following:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:

(A) the extension is not longer than five miles;

(B) the nominal pipe size is not larger than six inches; and

(C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;

(4) an interstate gas pipeline facility, as defined by 49 U.S.C. §60101, that is used for the transportation of sour gas; or

(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility.

(c) Filing and Assignment of Docket Number. Upon filing of an application with the Oil and Gas Division, staff will assign a docket number to the application and will notify the applicant of the assigned docket number. Staff will also assign and provide a docket number to a person who submits a notice of intent to file an application.

(d) Application. A complete application consists of:

(1) a properly completed application Form PS-79, with the original signature, in ink, of the applicant;

(2) if applicant desires notification under subsection (h)(1) by electronic mail, a written request for electronic mail notification and the applicant's electronic mail address;

(3) a plat which meets the requirements of subsection (f)(4) of this section and identifies the boundaries of surveys and blocks or sections as appropriate within the area of influence;

(4) a copy of the applicant's Application for Permit to Operate a Pipeline, Form T-4, if applicable, including all attachments; and

(5) a copy of the completed application for a Statewide Rule 36 Certificate of Compliance, Form H-9, including any attachment required under §3.36 of this title. A preliminary contingency plan may be filed in lieu of a contingency plan if required under §3.36 of this title.

(e) Notice.

(1) For each county that contains all or part of the area of influence of a proposed sour gas pipeline facility, the applicant shall:

(A) cause to be delivered to the county clerk no later than the first date of publication in that county a copy of the items described in subsection (d)(1) - (3) of this

section;

(B) publish notice of its application in a newspaper of general circulation in each county that contains all or a portion of the area of influence of the proposed sour gas pipeline facility. Such notice shall meet the requirements of subsection (f) of this section and be published in a section of the newspaper containing news items of state or local interest.

(2) Final action may not be taken on any application under this section until proof of notice, evidenced as follows, is provided:

(A) a return receipt from each county clerk with whom an application form and plat is required to be filed pursuant to paragraph (1) of this subsection; and

(B) the full page or pages of the newspaper containing the published notice required under paragraph (2) of this subsection including the name of the paper, the date the notice was published, and the page number.

(f) The published notice of application shall be at least three inches by five inches in size, exclusive of the plat, and shall contain the following:

(1) the name, business address, and telephone number of the applicant and of the applicant's authorized representative, if any;

(2) a description of the geographic location of the sour gas pipeline facility and the area of influence, to the extent not clearly identified in the plat required to be published in subsection (f)(4) of this section;

(F) by inset or otherwise, landmarks or other features such as roads and highways in relation to the proposed route of the sour gas pipeline facility. These landmarks or other features shall be of sufficient detail to allow a person to reasonably ascertain whether an owned or occupied property that is within the area of influence of the proposed sour gas pipeline facility. Examples of acceptable plats are included in this subsection.

(3) the following statement, completed as appropriate: "This proposed pipeline facility will transport sour gas that contains 100 parts per million, or more, of hydrogen sulfide. A copy of application forms and a map showing the location of the pipeline is available for public inspection at the offices of the (insert County name) County Clerk, located at the following address: (insert address of County Clerk). Any owner or occupant of land located within the area of influence of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to the application (by docket number if available) and stating their desire to protest to: Docket Services, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967. Protests shall be in writing and received by Docket Services not later than (specify 30th day after the first date notice of the application is to be published). The letter shall include the name, address, and telephone number of every person on whose behalf the protest is filed and shall state the reasons each such person believes that he or she is the owner or occupant of property within the area of influence of the proposed pipeline facility. It is recommended that a copy of this notice be included with the letter."; and

(4) a plat identifying:

(A) the location of the pipeline facility;

(B) area of influence;

(C) north arrow;

(D) scale;

(E) geographic subdivisions appropriate for the scale; and

NOTICE OF APPLICATION FOR PIPELINE PERMIT

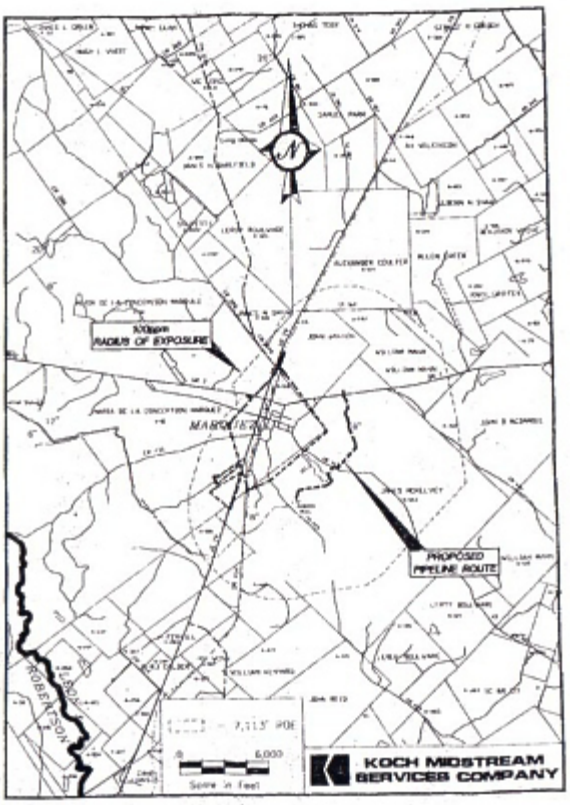
Koch Midstream Services Company, 606 S. Shelby St., Carthage, Texas 76533, has applied to the Railroad Commission of Texas for a permit to construct a 2.05 miles buried pipeline in Leon County, Texas, to gather natural gas containing hydrogen sulfide (Sour Gas). In the event of a leak, the radius of exposure of hydrogen sulfide for 100 parts per million (ppm) could extend 7113 feet on either side of the pipeline based on methods outlined in the 16 Texas Administration Code 3.36(2). The radius of exposure included parts of U.S. Hwy. 79 and extends northeasterly thru Marquez city limits. The applicant proposes to construct pipeline beginning 7,836 ft. southeasterly of a point of intersection of U.S. Hwy. 79 and State Hwy. 7 extending northeasterly 2.05 miles ending 5,808 ft. of a point of intersection of U. S. Hwy. 79 and State Hwy. 7. The city limits of Marquez are shown on the plat. The southwestern end of the pipeline will interconnect with a 8" sour gas pipeline owned and operated by the applicant. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines.

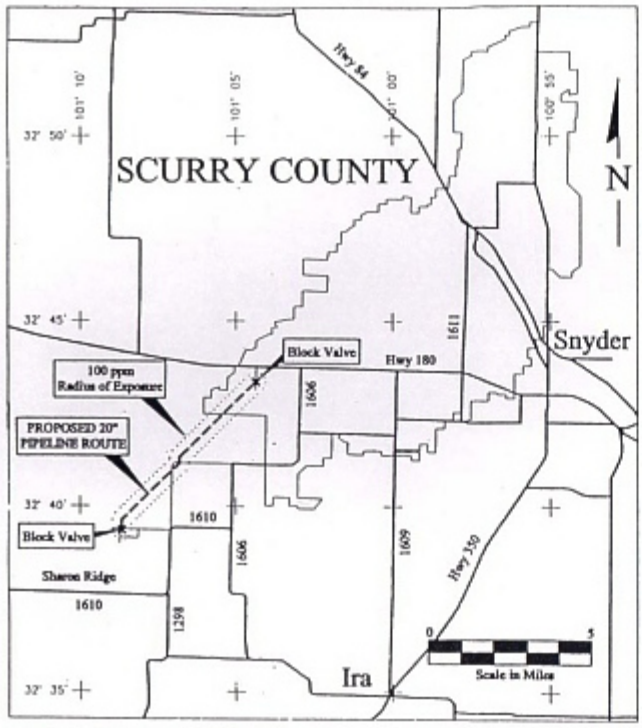
This proposed pipeline facility will transport sour gas that contains more than 100 ppm of hydrogen sulfide. A copy of this application is available for public inspection at the offices of the Leon County Clerk, located at the following address: the corner of Cass Street and St. Mary Street in Centerville, Texas.

Any owner or occupant of land located within 100 ppm radius of exposure of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket (GUD) No. 8899 and stating their desire to protest to:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P. O. Box 12967
Austin, Texas 78711-2967

Protests must be received no later than September 19, 1998. It is recommended that a copy of this notice be included with the letter. Additional information concerning the protest procedure can be obtained by calling (512) 463-7017 or by visiting\\www.rrc.state.tx.us\ on the Internet. For more information regarding this permit application you may contact Rob Koenig, Koch Midstream Services Company, 606 S. Shelby Street, Carthage, Texas 75633, Telephone: (903) 693-5172 ext. 2542.





NOTICE OF APPLICATION FOR PIPELINE PERMIT

PennzEnergy Exploration & Production, L.L.C., 4632 W Hwy 180, Snyder, Texas 79549, has applied to the Railroad Commission of Texas for a permit to construct 7.5 miles of 20" buried pipeline in Scurry County, Texas to gather produced gas at the Sharon Ridge Canyon Unit, Tank Battery 5. The gas transported within the proposed gas gathering line will contain concentrations of Hydrogen Sulfide greater than 100 ppm. In the event of a leak, the radius of exposure of Hydrogen Sulfide for 100 ppm could extend 1,577 feet on either side of the pipeline based on methods outlined in 16 Texas Administration Code 3.36. The radius of exposure of Hydrogen Sulfide for 500 ppm could extend 720 feet on either side of the pipeline. The proposed sour gas pipeline will be located in Scurry County as shown on the plat. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines. A copy of the application is available at the office of the Scurry County Clerk, located at 1806 25th Street, Snyder, Texas 79549.

Any owner or occupant of land located within the 100 ppm radius of exposure of the proposed sour gas pipeline desiring to protest can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket Number 8937 and stating their desire to protest:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

Protests must be received no later than May 1, 1999. It is recommended that a copy of this notice be included with the letter.

(g) Protests. Affected persons have standing to file a protest to an application. In the event the final proposed pipeline route is not known at the time of application, any person who owns or occupies real property located within the area of influence identified in the application shall have standing to file a protest to an application. All such protests shall:

(1) be in writing and filed at the commission no later than the 30th day after the notice is published in a newspaper in the county in which the person filing the protest owns or occupies real property;

(2) state the name, address, and telephone number of every person on whose behalf the protest is being filed; and

(3) include a statement of the facts on which the person filing the protest relies to conclude that each person on whose behalf the protest is being filed is an affected person, as defined in subsection (a)(1) of this section.

(h) Division Review.

(1) Within 14 days of receipt of the application, the commission's designee will provide notice to the applicant that the application is either complete and accepted for filing, or incomplete and specify the additional information required for acceptance. Such notice shall be provided in writing by mail or by electronic mail if the applicant submits with the application a written request that communications regarding application completeness or deficiencies be communicated by electronic mail and provides an accurate electronic mail address. The application shall be completed within 30 days of notification that the application is incomplete or such longer time as may be requested by the applicant, in writing, and approved by the commission's designee. If the application is not completed within the specified time period, the commission's designee shall send notice of intent to deny the application to the applicant. Within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the applicant may request a hearing on the application as it exists at that time. If a request for hearing is not filed within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the application shall be dismissed without prejudice by the commission's designee.

(2) The commission's designee shall make a written recommendation as to whether the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission if the application is not protested, by the latter of the 14th day after the end of the 30-day protest period or the 14th day after the day notice of a complete application is issued.

(3) If, pursuant to subsection (i) of this section, a hearing is held, the staff may introduce evidence relating to the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility.

(4) In determining whether or not the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission, relevant provisions of §3.36 and §3.70 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, and Pipeline Permits Required, respectively) shall be considered. If applicable, Chapter 8 of this title (relating to Pipeline Safety Regulations) shall also be considered.

(5) If no affected person files a protest with the commission by the 30th day after the date notice of application was published, the commission's designee shall either make a written recommendation that the permit be issued, that the permit be granted subject to specific conditions required to ensure compliance with applicable laws and regulations, or that the permit be denied. If the commission's designee recommends that the permit be conditionally granted or be denied, the reasons for such recommendation shall be explained. If the commission's designee recommends that the application be conditionally granted or be denied, the applicant shall have a right to a hearing upon written request received no later than 15 days after the date of issuance of notice of conditional grant or denial.

(i) Hearing.

(1) A hearing shall be convened to consider an application for a sour gas pipeline construction permit if:

(A) a protest is timely filed by an affected person;

(B) a request is timely filed by the applicant; or

(C) the commission so elects on its own motion.

(2) The Office of General Counsel shall assign an examiner who shall conduct a hearing in accordance with the procedural requirements of Texas Government Code, Chapter 2001 (the Administrative Procedure Act), and Chapter 1 of this title (relating to the general rules of practice and procedure).

(3) The commission shall convene a hearing not later than the 60th day after a protest is filed, the applicant submits a request for hearing, or the commission gives notice of intent to convene a hearing on its own motion. If the application is not complete as of the date the request for hearing is filed or notice of hearing issued, the 60-day time period for convening a hearing shall not begin to run until such time as notice of a complete application is issued unless the hearing is held pursuant to the provisions of subsection (h)(1). If the hearing is held pursuant to the provisions of subsection (h)(1), the hearing will be held within 60 days of receipt of a request for hearing.

(4) In any hearing convened to consider an application, the applicant has the burden of showing that the materials to be used in and method of construction and operation comply with the applicable rules and safety standards adopted by the commission.

(j) Order.

(1) An order approving an application shall include a finding that the materials to be used in and method of construction and operation of the facility comply with the applicable rules and safety standards adopted by the commission. If an application meets all the requirements of §3.70 of this title, relating to Pipeline Permits Required, including the requirements of §3.36 of this title, relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, the order may approve the certificate of compliance (Form H-9) or grant the pipeline permit or both.

(2) An order denying an application shall state the

reason or reasons for the denial.

(3) In the case of an application for which a hearing is conducted, the commission will render a decision not later than the 60th day after the date on which the hearing is finally closed.

(4) If no hearing is held on an application, the commission will render a decision as soon as practicable but not later than the 60th day after the staff prepares its written recommendation in accordance with subsection (h)(2) and (4).

Source Note: The provisions of this §3.106 adopted to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.107 Penalty Guidelines for Oil and Gas Violations

(a) Policy. Improved safety and environmental protection are the desired outcomes of any enforcement action. Encouraging operators to take appropriate voluntary corrective and future protective actions once a violation has occurred is an effective component of the enforcement process. Deterrence of violations through penalty assessments is also a necessary and effective component of the enforcement process. A rule-based enforcement penalty guideline to evaluate and rank oil- and natural gas-related violations is consistent with the central goal of the Commission's enforcement efforts to promote compliance. Penalty guidelines set forth in this section will provide a framework for more uniform and equitable assessment of penalties throughout the state, while also enhancing the integrity of the Commission's enforcement program.

(b) Only guidelines. This section complies with the requirements of Texas Natural Resources Code, §81.0531 and §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution. The penalty amounts shown in the tables in this section are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of provisions of Texas Natural Resources Code, Title 3; Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. This rule does not contemplate automatic enforcement. Violations can be corrected by operators before being referred to legal enforcement.

(c) Commission authority. The establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The guideline minimum penalties listed in this section are for the most common violations cited; however, this is neither an exclusive nor an exhaustive list of violations that the Commission may cite. The Commission retains full authority and discretion to cite violations of Texas Natural Resources Code, Title 3; including Nat. Res. Code §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section.

(d) Factors considered. The amount of any penalty requested, recommended, or finally assessed in an enforcement action will be determined on an individual case-by-case basis for each violation, taking into consideration the following factors:

(1) the person's history of previous violations;

(2) the seriousness of the violation;

(3) any hazard to the health or safety of the public; and

(4) the demonstrated good faith of the person charged.

(e) Typical penalties. Regardless of the method by which the guideline typical penalty amount is calculated, the total penalty amount will be within the statutory limit.

(1) A guideline of typical penalties for violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, are set forth in Table 1.

Table 1. Penalty Guideline

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.2	Commission denied access	$1,000
16 TAC §3.3	failure to comply with well sign requirements	$500
16 TAC §3.3	failure to comply with entrance sign requirements	$1,000
16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000
16 TAC §3.5(a)	no drilling permit approved	$5,000
16 TAC §3.5(a)	no drilling permit: no application filed	$10,000

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000
16 TAC §3.9(1)	no permit to dispose or inject	$5,000
16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve
16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000
16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000
16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000
16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500
16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500
16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000
16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth
16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total depth, subject to statutory maximum
16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum
16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000
16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000
16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500
16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000
16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000
16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000
16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500
16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000
16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500
16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500
16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000
16 TAC §3.21(a)-(i)	improper fire prevention	$1,000
16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500
16 TAC §3.21(k)	swabbing without authority	$1,000 per well
16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000
16 TAC §3.22	no nets	compliance
16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000
16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000
16 TAC §3.36(c)(6)(C)	materials provision	$2,500
16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000
16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000

As in effect on 12/9/2024.

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000
16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000
16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000
16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000
16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000
16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000
16 TAC §3.46(a)	no permit to dispose or inject	$5,000
16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve
16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.57	reclamation plant operation violation	$1,000
16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000
16 TAC §3.65(g)	failure to provide critical customer information	$2,500
16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000
16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000
16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000
16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000
16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000
16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000
16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well
16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well
16 TAC §3.99(g)	failure to file completion report	$1,000 per well
16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole
16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole
16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey
16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000
16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000
16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000
Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form

(2) Guideline penalties for violations of §3.73 of this title, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance, include additional penalty amounts that are based on four components. In combination, these four components yield the factor by which an additional penalty amount of $1,000 is multiplied. The various combinations of the components are set forth in Table 1A.

(A) The first component is the length of the violation. A low rating means the violation has been in existence less than three months. A medium rating means the violation has been outstanding for more than three months and up to one year. A high rating means the violation has been outstanding for more than one year.

(B) The second component is production value. A low rating means the value of the production is less than $5,000. A medium rating means the value of the production is more than $5,000 and up to $100,000. A high rating means the value of the production is more than $100,000.

(C) The third component is the number of unresolved severances. A low rating means there are fewer than two unresolved severances. A medium rating means there are more than two and up to six unresolved severances. A high rating means there are more than six unresolved

severances.

(D) The fourth component is the basis of the severance. The letter "N" indicates that the severance is not pollution related. The letter "Y" indicates that the severance is pollution related.

Table 1A. Calculation of Additional Guideline Penalty Amounts for Violations of 16 Tex. Admin. Code §3.73, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance

Length of Violation Low: < 3 mos. Medium: High: > 1 yr.	Production Value Low: < $5,000 Medium: High: > $100,000	Unresolved Severances Low: < 2 Medium: High: > 6	Basis of Severance N: non-pollution related Y: pollution related	Factor
low	low	low	N	1.0
low	low	medium	N	1.5
low	low	high	N	1.5
low	medium	low	N	1.5
low	medium	medium	N	3.5
low	medium	high	N	5.0
low	high	low	N	4.5
low	high	medium	N	7.0
low	high	high	N	7.5
medium	low	low	N	1.5
medium	low	medium	N	2.5
medium	low	high	N	3.5
medium	medium	low	N	3.5
medium	medium	medium	N	5.0
medium	medium	high	N	8.0
medium	high	low	N	8.5
medium	high	medium	N	9.0
medium	high	high	N	10.0
high	low	low	N	2.5
high	low	medium	N	3.5
high	low	high	N	3.5
high	medium	low	N	4.5
high	medium	medium	N	7.5
high	medium	high	N	8.0
high	high	low	N	10.0
high	high	medium	N	10.0
high	high	high	N	10.0
low	low	low	Y	1.5
low	low	medium	Y	2.0
low	low	high	Y	2.5
low	medium	low	Y	3.0
low	medium	medium	Y	5.0
low	medium	high	Y	7.5
low	high	low	Y	5.0
low	high	medium	Y	8.0
low	high	high	Y	8.5
medium	low	low	Y	2.0
medium	low	medium	Y	3.5
medium	low	high	Y	7.0
medium	medium	low	Y	7.0
medium	medium	medium	Y	7.5
medium	medium	high	Y	8.5
medium	high	low	Y	9.0
medium	high	medium	Y	9.5
medium	high	high	Y	10.0
high	low	low	Y	3.0
high	low	medium	Y	4.0

Length of Violation Low: < 3 mos. Medium: High: > 1 yr.	Production Value Low: < $5,000 Medium: High: > $100,000	Unresolved Severances Low: < 2 Medium: High: > 6	Basis of Severance N: non-pollution related Y: pollution related	Factor
high	low	high	Y	5.0
high	medium	low	Y	5.0
high	medium	medium	Y	8.5
high	medium	high	Y	9.0
high	high	low	Y	10.0
high	high	medium	Y	10.0
high	high	high	Y	10.0

(f) Penalty enhancements for certain violations. For violations that involve threatened or actual pollution; result in threatened or actual safety hazards; or result from the reckless or intentional conduct of the person charged, the Commission may assess an enhancement of the guideline penalty amount. The enhancement may be in any amount in the range shown for each type of violation as shown in Table 2.

Table 2. Penalty Enhancements

Evidentiary Factors	Threatened or Actual Pollution	Safety Hazard	Severity of Violation
Agricultural land or sensitive wildlife habitat	$1,000 to $5,000		
Endangered or threatened species	$2,000 to $10,000		
Bay, estuary or marine habitat	$5,000 to $25,000		
Minor freshwater source (minor aquifer, seasonal watercourse)	$2,500 to $7,500		
Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)	$5,000 to $25,000		
Impacted residential/public areas		$1,000 to $15,000	
Hazardous material release		$2,000 to $25,000	
Reportable incident/accident		$5,000 to $25,000	
Well in H_2S field		up to $10,000	
Time out of compliance			$100 to $2,000 / month
Reckless conduct of operator			double total penalty
Intentional conduct of operator			triple total penalty

(g) Penalty enhancements for certain violators. For violations in which the person charged has a history of prior violations within seven years of the current enforcement action, the Commission may assess an enhancement based on either the number of prior violations or the total amount of previous administrative penalties, but not both. The actual amount of any penalty enhancement will be determined on an individual case-by-case basis for each violation. The guidelines in Tables 3 and 4 are intended to be used separately. Either guideline may be used where applicable, but not both.

Table 3. Penalty enhancements based on number of prior violations within seven years

Number of violations in the seven years prior to action	Enhancement amount
One	$1,000
Two	$2,000
Three	$3,000
Four	$4,000
Five or more	$5,000

Table 4. Penalty Enhancements based on total amount of prior penalties within seven years

Total administrative penalties assessed in the seven years prior to	Enhancement amount

action	
Less than $10,000	$1,000
Between $10,000 and $25,000	$2,500
Between $25,000 and $50,000	$5,000
Between $50,000 and $100,000	$10,000
Over $100,000	10% of total amount

(h) Penalty reduction for accelerated settlement before hearing. The recommended monetary penalty for a violation may be reduced by up to 50% if the person charged agrees to an accelerated settlement before the Commission conducts an administrative hearing to prosecute a violation. Once the hearing is convened, the opportunity for the person charged to reduce the basic monetary penalty is no longer available. The reduction applies to the basic penalty amount requested and not to any requested enhancements.

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

(j) Penalty calculation worksheet. The penalty calculation worksheet shown in Table 5 lists the guideline minimum penalty amounts for certain violations; the circumstances justifying enhancements of a penalty and the amount of the enhancement; and the circumstances justifying a reduction in a penalty and the amount of the reduction.

Table 5. Penalty Calculation Worksheet

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
1	16 TAC §3.2	Commission denied access	$1,000	$
2	16 TAC §3.3	failure to comply with well sign requirements	$500	$
3	16 TAC §3.3	failure to comply with entrance sign requirements	$1,000	$
4	16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000	$
5	16 TAC §3.5(a)	no drilling permit: filed but not approved	$5,000	$
6	16 TAC §3.5(a)	no drilling permit: no application filed	$10,000	$
7	16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum	$
8	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.	$
9	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.	$
10	16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
11	16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.	$
12	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
13	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.	$
14	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500	$
15	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000	$
16	16 TAC §3.9(1)	no permit to dispose or inject	$5,000	$
17	16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000	$
18	16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve	$
19	16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000	$
20	16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000	$
21	16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000	$
22	16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000	$
23	16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500	$
24	16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500	$
25	16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000	$
26	16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth	$
27	16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total	$

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
			depth, subject to statutory maximum	
28	16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum	$
29	16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000	$
30	16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000	$
31	16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500	$
32	16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000	$
33	16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000	$
34	16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000	$
35	16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500	$
36	16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000	$
37	16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500	$
38	16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500	$
39	16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000	$
40	16 TAC §3.21(a)-(i)	improper fire prevention	$1,000	$
41	16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500	$
42	16 TAC §3.21(k)	swabbing without authority	$1,000 per well	$
43	16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000	$
44	16 TAC §3.22	no nets	compliance	
45	16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000	$
46	16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000	$
47	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000	$
48	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000	$
49	16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000	$
50	16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000	$
51	16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000	$
52	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000	$
53	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000	$
54	16 TAC §3.36(c)(6)(C)	materials provision	$2,500	$
55	16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000	$
56	16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500	$
57	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000	$

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
58	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000	$
59	16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000	$
60	16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000	$
61	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000	$
62	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000	$
63	16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000	$
64	16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person	$
65	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000	$
66	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000	$
67	16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000	$
68	16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000	$
69	16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000	$
70	16 TAC §3.46(a)	no permit to dispose or inject	$5,000	$
71	16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000	$
72	16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve	$
73	16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000	$
74	16 TAC §3.57	reclamation plant operation violation	$1,000	$
75	16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000	$
76	16 TAC §3.65(g)	failure to provide critical customer information	$2,500	$
77	16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000	$
78	16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
79	16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
80	16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000	$
81	16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000	$
82	16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000	$
83	16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000	$
84	16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000	$
85	16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well	$
86	16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well	$

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
87	16 TAC §3.99(g)	failure to file completion report	$1,000 per well	$
88	16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole	$
89	16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole	$
90	16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey	$
91	16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000	$
92	16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000	$
93	16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000	$
94	Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form	$
95	**Subtotal of guideline penalty amounts from Table 1 (lines 1-94, inclusive)**			$
96	**Reduction for settlement before hearing: up to 50% of line 95 amt.**		_____ %	$
97	**Subtotal: amount shown on line 95 less applicable settlement reduction on line 96**			$
	Penalty enhancement amounts for threatened or actual pollution from Table 2			
98	Agricultural land or sensitive wildlife habitat		$1,000 to $5,000	$
99	Endangered or threatened species		$2,000 to $10,000	$
100	Bay, estuary or marine habitat		$5,000 to $25,000	$
101	Minor freshwater source (minor aquifer, seasonal watercourse)		$2,500 to $7,500	$
102	Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)		$5,000 to $25,000	$
	Penalty enhancement amounts for safety hazard from Table 2			
103	Impacted residential/public areas		$1,000 to $15,000	$
104	Hazardous material release		$2,000 to $25,000	$
105	Reportable incident/accident		$5,000 to $25,000	$
106	Well in H_2S field		up to $10,000	$
	Penalty enhancement amounts for severity of violation from Table 2			
107	Time out of compliance		$100 to $2,000 each month	$
108	**Subtotal: amount shown on line 97 plus all amounts on lines 98 through 107, inclusive**			$
	Penalty enhancements for culpability of person charged from Table 2			
109	Reckless conduct of operator		double line 108 amount	$
110	Intentional conduct of operator		triple line 108 amount	$
	Penalty enhancements for number of prior violations within past seven years from Table 3			
111	One		$1,000	$
112	Two		$2,000	$
113	Three			

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
			$3,000	$
114	Four		$4,000	$
115	Five or more		$5,000	$
	Penalty enhancements for amount of penalties within past seven years from Table 4			
116	Less than $10,000		$1,000	$
117	Between $10,000 and $25,000		$2,500	$
118	Between $25, 000 and $50,000		$5,000	$
119	Between $50,000 and $100,00		$10,000	$
120	Over $100,000		10% of total amt.	$
121	**Subtotal: Line 97 amt. plus amts. on line 109 and/or 110 plus the amt. shown on any line from 111 through 120, inclusive**			$
122	**Reduction for demonstrated good faith of person charged**			$
123	**TOTAL PENALTY AMOUNT: amount on line 121 less any amount shown on line 122**			$

Source Note: The provisions of this §3.107 adopted to be effective August 27, 2012, 37 TexReg 6540; amended to be effective December 20, 2021, 46 TexReg 8688.

Figure: 16 TAC §3.66(g)(1)

Classification System

Violation Factors		Factor Value	Points Tally
Oil lease or gas well facility out of compliance with §3.66 produces an average of 5,000 Mcf or more of natural gas per day		4	
Oil lease or gas well facility out of compliance with §3.66 produces an average of 1,000 Mcf or more per day but less than 5,000 Mcf of natural gas per day		3	
Oil lease or gas well facility out of compliance with §3.66 produces an average of 500 Mcf or more per day but less than 1,000 Mcf of natural gas per day		2	
Oil lease or gas well facility out of compliance with §3.66 produces an average of 250 Mcf or more per day but less than 500 Mcf of natural gas per day		1	
Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that resulting in a loss of processing, storage withdrawal, or transportation of 200 MMcf or more of natural gas per day		4	
Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that results in a loss of processing, storage withdrawal, or transportation capacity 100 MMcf or more per day but less than 200 MMcf of natural gas per day		3	
Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that results in a loss of processing, storage withdrawal, or transportation capacity of less than 100 MMcf of natural gas per day		2	
Actual Hazard to health, safety, or economic welfare of the public		5	
Potential hazard to health, safety, or economic welfare of the public		2	
Time out of compliance (calculated as days the operator fails to remedy a violation noted in a Commission notice of violation)	90 days or greater	4	
	60 days or more but less than 90 days	3	
	30 days or more but less than 60 days	2	
	5 days or more but less than 30 days	1	
Reckless conduct of operator		3	
Intentional conduct of operator		5	
Repeat violations based on operator's history of compliance		3	
Good faith effort to remedy violation		-2	
No effort to remedy violation		5	
During the weather emergency in which the facility's violation occurred, the operator had no reduction in the natural gas supplied to the Texas electricity supply chain		-3	

As in effect on 12/9/2024.

During the weather emergency in which the facility's violation occurred, the operator of a saltwater disposal well had no reduction in saltwater disposal capacity made available to Texas electricity supply chain facilities.	-3	
		Total
		Penalty maximum per violation
15 points or more = Class A violation		$More than 5,000[1]
10-14 points = Class B violation		$5,000
5-9 points = Class C violation		$4,000
1-4 points = Class D violation		$3,000

[1] Pursuant to Natural Resources Code §86.222, the required classification system shall provide that a penalty in an amount that exceeds $5,000 may be recovered only if the violation is included in the highest class of violations in the classification system.

As in effect on 12/9/2024.