TEXAS (07/2019)

I. Administration

1. Agency regulating oil and gas exploration/production: Railroad Commission of Texas (RRC).

2. Contact for regulatory updates: Leslie Savage at leslie.savage@rrc.texas.gov.

3. Docketing procedure:

    a. Emergency orders: See 16 TAC Chapter 1, relating to Practice and Procedure at http://www.rrc.state.tx.us/rules/rule.php.

    b. Notice: See 16 TAC Chapter 1, relating to Practice and Procedure at http://www.rrc.state.tx.us/rules/rule.php.

4. Agency regulating air emissions: Texas Commission on Environmental Quality (TCEQ).

5. Agency regulating water quality: Both TCEQ and RRC/EPA

II. License

1. License required: Operators required to file and maintain an approved Organization Report. See 16 Texas Administrative Code (TAC) §3.1(a)-(h), relating to Organization Report; Retention of Records; Notice Requirements.

2. Conditions of license: Must renew annually. Financial security. All entities who perform operations within RRC jurisdiction must 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 RRC rules and regulations in connection with the performance of such operations. Operators must make books available for inspection of the RRC and must report such information as required by the RRC. Each organization that files for federal bankruptcy protection must provide written notice to the RRC of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection. 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 RRC may refuse to renew the operator's organization report, until the operator pays the required fee and the RRC issues the certificate of compliance required for that well.

III. Financial Security

1. §3.78(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. Subsection (g)(7) exempts a person who is not an operator of wells if the person's only activity is as a first purchaser, survey company, saltwater hauler, gas nominator, gas purchaser and/or well plugger.

2. Purpose of surety: Proper plugging of wells under RRC's jurisdiction; closure of pits and cleanup of leases and other facilities.

3. Plugging and restoration: Yes.

4. Compliance bond required: Yes.

5. Types of security required: Individual performance bond; blanket performance bond; or a letter of credit or cash deposit; or individual well plugging insurance policy.

6. §3.78(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:

    (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 RRC-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) 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), 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 RRC 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 RRC 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 RRC 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 organizational report)

(B) If the director administratively denies a requested reduction, the operator may request a hearing to determine whether the reduction should be granted.

RRC rules also include provisions and procedures for a reduction in additional financial security required for bay and/or offshore wells that are not actively producing oil and natural gas.

(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 RRC. 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. RRC 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. RRC 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 RRC 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.

(m) Effect of outstanding violations.

(1) Except as provided in paragraph (2), the RRC 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 RRC shall accept a report or application or approve a certificate filed by an organization covered by paragraph (1) 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 RRC;

(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 RRC; and

(C) the report, application or certificate is in compliance with all other requirements of law and RRC rules.

(3) All fees tendered in connection with a report or application that is rejected under this subsection are nonrefundable.

(l) Financial security for commercial facilities. The RRC also requires financial security for commercial facilities. Such an applicant must submit: (i) a written estimate of the maximum dollar amount necessary to close the facility;

(ii) a copy of the form of the bond or letter of credit that will be filed with RRC; and

(iii) information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or LOCs in Texas.

(4) Amount.

(A) Except as provided for 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 RRC 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, RRC 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 already filed as financial security under subsection (g)(6) of this section. The full amount of financial security required under subparagraph (A) if 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 for 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 RRC to pay the costs of plugging any well or wells at the facility if the financial security for plugging costs filed with the RRC 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 RRC 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 RRC or its delegate.

IV. Land Leasing Information

1. Leasing method:

The Lands and Minerals Division of the Texas General Land Office (TGLO) holds lease sales for oil and gas on State lands. TGLO manages Texas State resources for the benefit of public education. TGLO holds sales quarterly in January, April, July, and October. Because of holidays, sales are usually held on the first Tuesday of the month in January and July. Nominations for a sale are due 2 weeks after the previous sale date (e.g., nominations for the July sale would be due 2 weeks following the date of the April sale).

The TGLO developed the Energy Land and Lease Inventory System (TGLO, 2010) as an Internet mapping application that provides the public with land and lease information about State-owned submerged lands. Because Energy Land and Lease Inventory System is a tool and not the formal notification, prospective bidders should refer to the Notice for Bids and addenda to obtain the marginal number and minimum bid of the tract that they wish to bid upon for an upcoming oil and gas lease sale because the Notice for Bids and addenda are controlling. The TGLO Mineral Leasing Division uses a sealed bid process for the leasing of State lands.

The most recent oil and gas lease sale occurred in January of 2017. 105 state lease tracts, containing 26,609.1755 net mineral acres, of State lands, spread over 14 counties was offered for oil and gas leasing by EnergyNet, who now handles the TGLO’s bidding process. The number of acres offshore was unspecified.

TGLO uses sealed bid sales. During a sealed bid sale, GLO allows an oil or gas company to make a cash offer for the right to explore and produce hydrocarbons on a particular piece of state property. The company offering the highest up-front payment, or bonus, wins the lease. GLO also receives a percentage of any production from the lease, called a royalty.

Lease sales are held in January, April, July and October. Sales are usually held on the first Tuesday of the month.

Oil and gas underlying state lands are leased in the following ways, depending on the type of land.

(1) Permanent School Fund uplands, submerged lands, riverbeds and channels. PSF uplands submerged lands, riverbeds and channels are leased by the SLB under sealed bid procedures. For SLB sealed bid procedures see TNRC, Chapter 32, Subchapters D and E, Chapter 52, Subchapter B, §9.22(1) of this title, (relating to Leasing Procedures), and Chapter 151 of this title, (relating to General Rules of Practice and Procedure). For only riverbeds and channels, also see Texas Natural Resources Code, Chapter 52, Subchapter C.

(2) PSF oil and gas interests owned with associated mineral leasing rights. Generally, whenever the PSF owns mineral interests coupled with leasing rights, oil and gas leases are issued by the SLB under the sealed bid procedures of paragraph (1) of this subsection. (For examples of these types of PSF mineral interests, see Texas Natural Resources Code, §51.054(a), §32.061 (see especially historical legislative note), §33.001(g), or §51.052(h).)

(3) PSF oil and gas interests owned without associated mineral leasing rights. (A) Relinquishment Act lands. Leases are generally negotiated by surface owners as agents for the state. See Texas Natural Resources Code, Chapter 52, Subchapter F, and §9.22(2), and §9.22(3). Note: Relinquishment Act lands owned by a department, board, or agency of the state, including TDCJ land, TPWD land, and highway rights-of-way land, are leased under the sealed bid procedures of paragraph (1) of this subsection. See Texas Natural Resources Code, §32.002(d) and §34.002(b). (B) Free royalty lands. Leases are issued by the executive right holders as the state's agents. See §9.22(4).

2. Notice method: The Texas General Land Office (GLO) holds four oil and gas lease sales each year, in January, April, July and October, typically on the first or third Tuesday. In order to request that a state-owned tract be offered at a lease sale, the tract must be nominated. Nominations must be submitted in writing by the deadline set prior to each lease sale. A $100.00 Nomination Fee must be paid for each tract nominated. More than one tract may be included in the nomination letter.

3. Minimum bidding $ (per acre):

4. Qualification of the bidder:

5. State statutes: Title 31, Part 1, Chapter 9, relating to Exploration and Leasing of State Oil and Gas.

6. Maximum acres: Gulf of Mexico and bay tracts containing 640 acres (except shoreline tracts) have been divided into north and south halves for nomination and bidding purposes (northeast and southwest halves in the Galveston Bay and Corpus Christi Bay systems). Shoreline tracts are divided on a case-by-case basis. Gulf of Mexico tracts containing 5,760 acres have been divided into north and south halves of each quarter (720 acres) for nomination and bidding purposes.

7. Royalty rates: The Permanent School Fund gains revenue from a portion of the production, depending on the particular free royalty reservation, which is usually a 1/16 or 1/8th free royalty interest. Typically, the Land Office receives about 20 to 25 percent royalty from oil or gas produced from our leases on state land. The Land Office can take this royalty in cash or in actual oil and gas, which can be sold competitively to public entities as gas or electricity.

8. Agency in control of leasing: Texas General Land Office (Robert Hatter at (512) 475-1542 or George Martin at (512) 475-1512).

V. Setbacks

1. Under §81.0523 of the Texas Natural Resources Code, an oil and gas operation is subject to the exclusive jurisdiction of the state of Texas. Except as provided by Subsection (c), a municipality of 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.

2. (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:

    a. (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 of reasonable setback requirements;

    b. (2) is commercially reasonable;

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

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

3. (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.

VI. **Spacing**

1. Spacing requirements:

   a. Density: §3.38 Well Densities

   (1) General prohibition. No well may 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 Requirements
(1) 150 - 300	2
(2) 200 - 400	4
(3) 330 - 660	10
(4) 330 - 933	20
(5) 467 – 933	20
(6) 467 – 1200	40
(7) 550 – 1320	40

   (B) The spacing rules listed above are not exclusive. Any spacing rule not listed above is brought to the attention of the RRC 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 RRC 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); or

(B) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title) 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); and that

(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 RRC, and the unit has produced hydrocarbons in the preceding 20 years, the unit may not thereafter be dissolved into the separate tracts with RRC rules 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 RRC approves such dissolution.

(B) RRC 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 RRC designee may grant administrative approval if the designee determines that granting the application will not result in the circumvention of the density restrictions of this section or other RRC rules, and if either written waivers are filed by all affected persons; or 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 RRC 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

(f) Exceptions to density provisions authorized. The RRC or its designee, in order to prevent waste or, except as provided in subsection (d)(2) of this section, to prevent waste or, 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 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 completes to the best of that person's knowledge.

(2) Plat. When filing an application for an exception to density requirements, in addition to the plat requirements in §3.5, the applicant must 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).

(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 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) must be filed on Form W-1A, Substandard Acreage Certification.

(A) The operator must 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 must 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 RRC's Austin office and a copy with the appropriate district office, unless the operator files electronically through the Commission's Electronic Compliance and Approval Process (ECAP) system.

(D) The operator or the operator's agent must 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):

(A) a list of the names and addresses of all affected persons. For the purpose of giving notice of application, the RRC 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. RRC 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 RRC.

(2) Notice of application. Upon receipt of a complete application, the RRC 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 RRC designee determines, based on the data submitted, that a permit requiring an exception to the applicable density provision is justified, then the RRC designee may issue the exception permit administratively if:

(A) signed waivers from all affected persons were submitted with the application; or

(B) proper notice of application was given and no protest was filed within 21 days of the notice or no person appeared to protest the application at a hearing.

(4) Hearing on the application.

(A) If a written protest is filed within 21 days after the notice of application is given, the application will be set for hearing.

(B) If the application is not protested and RRC determines that a permit requiring an exception to the applicable density provision is not justified, the operator may request a hearing to consider the application.

(i) Duration. A permit is issued as an exception to the applicable density provision expires 2 years from the effective date of the permit; unless drilling operations are commenced in good faith within the two year period.

b. Lineal: [16 TAC §3.37] Statewide Spacing Rule.

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource may 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 may be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided RRC, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances when RRC determines 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 and the appropriate form according to the instructions on the form, accompanied by a plat 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) 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), or after a public hearing held after at least 10 days notice to all persons described in paragraph (2). 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 RRC will presume that every person described in paragraph (2) 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) 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 (Application to Drill, Deepen, Reenter, or Plug Back), 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); (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 RRC 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.

(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 RRC 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 RRC 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 RRC 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 RRC 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.

2. Exceptions:

    a. Basis:

    b. Approval:

(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 RRC that this order shall not be final until 20 days after it is actually mailed to the parties by RRC; 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 RRC. 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 is required to be given.

(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 RRC's discretion to set any application for hearing. If 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 RRC for completions requiring an exception to this section shall expire 2 years from the effective date of the permit unless drilling operations are commenced in good faith within the 2-year permit period. The permit period will not be extended.

(2) So long as a Rule 37 exception is in litigation, the 2-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 can be entertained except on changed conditions. Changed conditions in RRC’s administration of 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 RRC 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 RRC 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 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 and 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 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 RRC 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 the 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 the 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 RRC order;

(4) that the current operator of the well or his predecessor has not filed either a false inclination or a false directional survey with RRC.

(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 RRC 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 RRC 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.

VII. Pooling

1. Authority to establish voluntary pooling:

16 TAC §3.40, relating to 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 the Form P-12.

(2) The operator must provide information on the Certificate of Pooling Authority, Form P-12, accurately and according to the instructions on the form.

(A) The operator separately list each tract committed to the pooled unit by authority granted to the operator

(B) For each listed tract, shall state the number of acres contained within the tract; shall indicate 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 individual 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 plant and/or Form P-12.

(4) The operator must file the Form P-12 and 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 RRC purposes to obtain a drilling permit;

(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 completion report has been filed; or

(D) to designate a change in a pooled unit previously recognized by the RRC. The operator shall file any changes to a pooled unit in accordance with the requirements of §3.38(d)(3) (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 RRC shows that a certain undivided interest is outstanding in the tract. The RRC will not allow an operator to assign only his undivided interest out of a basic tract, where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains his development rights in his basic tract, If the development rights are exercised, the RRC grants authority to develop the basic tract, and a well completed as a producer thereon, then the entire interest in the basic tract must be allocated to said well, and any interest insofar as it is pooled with another tract must be assigned to the well on the basic tract for allocation purposes. Splitting of undivided interest in a basic tract between two or more wells on two or more tracts is not acceptable.

(d) Except as provided in subsection (e) of this section, acreage assigned to a well for drilling and development, or for allocation of allowable, shall not be assigned to any other well or wells completed or projected to be completed in the same field; such duplicate assignment of acreage is not acceptable. However, this limitation shall not prevent the reformation of development or proration units so long as:

(1) no duplicate assignment 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, duplicate assignment of acreage to both a horizontal well and a vertical well for drilling and development or for allocation of allowable is permissible as follows:

(1) 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.

(2) Acreage assigned to horizontal wells for drilling and development, or for allocation of allowable, shall be acceptable so long as the horizontal well density complies with §3.38 of this title and/or special field rules, as applicable.

(3) Acreage assigned to vertical wells for drilling and development, or for allocation of allowable, shall be acceptable so long as the vertical well density complies with §3.38 of this title and/or special field rules, as applicable.

(4) For the purposes of this section, stacked lateral wells as defined in §3.86(a)(10) of this title are not considered duplicate assignment of acreage to multiple horizontal wells.

(f) 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.

(g) 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. 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.

2. Authority to establish compulsory:

VIII. Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: No.

2. Minimum percentage of voluntary agreement before approval of compulsory unitization:

   a. Working interest:

   b. Royalty interest:

IX. Drilling Permit

1. Permits required for:

   a. Drilling a producing or service well: Yes.

   b. Seismic drilling: See 16 TAC §3.100 (Seismic Holes and Core Holes). A seismic hole or core hole that does not penetrate any protection depth does not require a drilling permit. 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) (Application To Drill, Deepen, Reenter, or Plug Back).

      On state-owned land, a permit from the Texas General Land Office to perform seismic work is required to ensure standards of safety and compliance are maintained. The fee is $100.00 per permit. All other applicable fees must be paid prior to issuance of a geophysical permit on state-owned lands. Additional fees may apply based on area, location and energy source: High velocity energy sources: $5.00 per acre in bays and other tideland areas; $2.00 per acre in the Gulf of Mexico; Low velocity energy sources: $2.50 per acre in bays and other tideland areas; $1.00 per acre in the Gulf of Mexico; and other exploration techniques- negotiable.

c. Recompletion: Permit required if recompletion into a different formation/reservoir.

d. Plugging and abandoning: No permit, but requires approval of plugging plan.

2. Permit fee:

a. Drilling: 16 TAC §3.78(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 RRC 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.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that RRC expedite the application for a permit to drill, deepen, plug back, or reenter a well.

	Current fee ($)	Surcharge ($)	Total fee ($)
Drilling permits less than 2,000 feet	200.00	300.00	500.00
Drilling permits 2,001 to 4,000 feet	225.00	337.50	562.00

Drilling permits 4,001 to 9,000 feet	250.00	375.00	625.00
Drilling permits greater than 9,000 feet	300.00	450.00	750.00
Expedite fee	150.00	225.00	375.00

b. Seismic drilling: See above.

c. Recompletion: See above.

d. Plugging and abandoning: No fee.

3. Require filing report of work performed: Yes.

4. Sundry notices used: Various notices required for drilling, producing, plugging.

X. Vertical Deviation

1. Regulation requirement **16 TAC §3.11**:

a. When is a directional survey necessary: 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 penalty action. However, an operator may submit a directional survey, run at his own expense by a RRC-approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When the 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 (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. See §3.11(c)(1)(A)

Directional surveys are required on each well drilled under the directional deviation provisions of this section. 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 RRC. See §3.11(1)(B) and (C)

Directional surveys must be run by competent surveying companies, approved by RRC, signed and certified by a person having actual knowledge of the facts, in the manner prescribed by RRC in accordance with §3.12 (Directional Survey Company Report). All directional surveys, unless otherwise specified by RRC, 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). 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. See §3.11(2)(A), (B), and (C)

Intentional deviation:

Directional deviation is defined as the intentional deviation of a well from vertical in a predetermined compass direction. RRC may grant a permit for directionally deviating a well: (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 RRC to be sufficient after notice and hearing.

Random deviation is defined as the intentional deviation of a well without regard to compass direction to straighten a hole which has become crooked in the normal course of drilling or to sidetrack a portion of a hole because of mechanical difficulty in drilling. RRC may grant permission for the random deviation of a well whenever the necessity for such deviation is shown. If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator must give written notice by letter of such necessity to the appropriate district office and to RRC office in Austin. Upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this section on inclination surveys.

(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 (Application to Drill, Deepen, Reenter, or Plug Back) , 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 of such necessity to the appropriate district office and to the RRC 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 submitted. 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 directional deviation arises unexpectedly after drilling had 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 RRC, 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. The complaining party must show probable cause to suspect that the well is not bottomed within its own lease lines and must agree to pay all costs and expenses of such survey, shall assume all liability, and post bond in a sufficient sum as security against all costs and risks associated with the survey. The complaining party and RRC must agree upon the surveying company to conduct the survey. The RRC must witness the survey. Any party, or his agent, who has an interest in the field may witness the survey.

b. Filing of survey required: Yes.

c. Format of filing: See 16 TAC §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 must prepare and file the following information. The information must 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 RRC 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 RRC in Austin by the surveying company making the survey. The surveying company may file electronically if the Commission has provided for such filing.

XI. Casing and Tubing

1. Minimum amount required 16 TAC §3.13:

   a. Surface casing: An operator must set and cement sufficient surface casing to protect all usable quality water strata, as defined by the Commission's Groundwater Advisory Unit. Unless surface casing requirements are specified in field rules, before drilling any well, an operator shall obtain a letter from the GAU stating the protection depth.

   b. Production casing:

2. Minimum amount of cement required:

   a. Surface casing: Sufficient cement must be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar.

   b. Production casing: Each intermediate string of casing shall be cemented from the shoe to a point at least 600' (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 TOC is determined through calculation, from the shoe up to a point at least 600' (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; (ii) if TOC is determined through performance of a temperature survey, from the shoe up to a point at least 250' (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; (iii) if the TOC is determined through performance of a cement evaluation log, from the shoe up to a point at least 100' (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’ (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.

c. Setting time: 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. Zone of critical cement-- (i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000’ nor less than 300’. The zone of critical cement extends to the land surface for surface casing strings of 300’ 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.

3. Tubing requirements:

   a. Oil wells: All flowing oil wells must 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’ (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’ (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’ (vertical depth) above the top of the perforated or open-hole interval actually open for production into the wellbore. Alternate programs requesting a temporary exception 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 of the rule. 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 must obtain approval of any alternative program before commencing operations.

   b. Gas wells: No requirements.

XII. Hydraulic Fracturing

1. Permitting:

    a. Before drilling: Drilling permit required. Requirements for wells to be fracture stimulated are included in [16 TAC 3.13], relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements.

    b. Before fracing: N/A

    c. How long before: N/A

2. Reporting requirements:

    a. Where reported: RRC and FracFocus.

    b. When reported: After fracture stimulation with completion report.

3. Source water requirements: N/A

4. Mechanical integrity:

    a. Cementing log required: If the surface casing is exposed to more than 360 rotating hours after reaching TD 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 MIT or equivalent RRC-approved casing evaluation method, unless otherwise approved by the district director. Also, see requirements for minimum separation wells below.

    b. Pressure testing: All casing strings or fracture tubing installed in a well that will be subjected to HFTs 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. The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during HFTs to at least the max pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve shall be tested to 80% of actuation pressure for a minimum time period of 5 minutes. A surface pressure loss of greater than 10% 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 TOC 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 HFT 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. Pressure monitoring: During hydraulic fracturing treatment (HFT) operations, the operator shall monitor all annuli. The operator shall immediately suspend HFT operations if the pressures deviate 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 HFT operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan.

d. Blowout preventer required: Yes – all wells.

The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director. A minimum separation well is a well in which HFTs will be conducted and for which: 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; 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 the director has determined is in a structurally complex geologic setting.

(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’ (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’ 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 HFT. The operator shall notify the district director within 24 hours of a failed test. No HFT 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 8 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 5 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 5 wells that have had successful cement jobs.

5. Disposal of flowback fluids:

   a. Retaining pits: Authorized (on-lease) or permitted (off-lease or centralized or commercial).

   b. Tanks: Yes.

   c. Approved discharge to surface water: RRC discharge permit and EPA NPDES permit required, but generally prohibited in Texas if untreated.

   d. Underground injection: Yes.

6. Chemical disclosure requirement:

   a. Mandatory: Yes, see 16 TAC §3.29.

   b. Where disclosed: FracFocus.org or, if FracFocus is temporarily inoperable, the operator of a well on which hydraulic fracturing treatment(s) were performed must supply the RRC 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 RRC's Internet website, until the RRC amends this rule to specify another publicly accessible Internet website.

c. When disclosed (pre-fracing, post-fracing, both): Post-Fracing.

d. (2)(A) Operator disclosures. On or before the date the completion report is required. Completion report required to be filed with the RRC 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. (16 TAC §3.16)

e. Information required to be disclosed:

(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 CFR §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.

f. (C) Trade secret protection: 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. Unless the information is entitled to protection as a trade secret under Texas Government Code, Chapter 552, information submitted to the RRC or uploaded on the Chemical Disclosure Registry is public information.

(4) Required disclosure to health/emergency personnel: A supplier, service company or operator may not withhold information related to chemical ingredients used in a HF 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 CFR §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. 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 CFR

§1910.1200(i) with respect to a written statement of need and confidentiality agreements, as applicable.

XIII. Underground Injection

1. Agencies that control the underground injection of fluid by well class:

   TCEQ: Class I, Class III (Uranium mining); Class IV, Class V, Class VI

   RRC: Class II, Class III (Brine mining); Class V; Class VI

XIV. Completion

1. Completion report required: See 16 TAC §3.16.

   a. Time limit: The operator of a well shall file with the RRC 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.

   b. Where submitted: RRC headquarters in Austin (electronic filing available).

2. Well logs required to be filed: See 16 TAC §3.16.

   a. Time limit: 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 RRC a legible and unaltered copy of a basic 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 RRC. In the event an electric log, as defined in this section, has not been run, subject to the RRC'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 RRC'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 RRC 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.

b. Where submitted: Electronically or to RRC Headquarters in Austin, Texas.

c. Delayed filing based on confidentiality. Each log filed with the RRC 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.

d. 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.

e. Available for public use: Yes, after confidentiality period.

f. Log catalog available: Available on-line for those received since July 2004. See http://www.rrc.state.tx.us/data/wells/wellrecords.php.

3. Multiple completion regulation: 16 TAC §3.6, relating to Application for Multiple Completion.

   a. Approval obtained: (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 RRC's Permitting and Production Section for its consideration and approval. (b) If the proposed zones of completion are not presently recognized by the RRC as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the RRC 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 RRC 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 RRC'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;

(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.

4. Commingling in well bore: 16 TAC §3.10, Restriction of Production of Oil and Gas from Different Strata.

    a. Approval obtained:

    (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.

XV. <u>Oil Production</u>

1. Definition of an oil well: Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas. (16 TAC §3.79, Definitions)

2. Potential tests required: 16 TAC §3.51, relating to Oil Potential Test Forms Required

    a. A completed potential test form shall be filed with the RRC no 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 RRC. This 30-day provision shall govern regardless of whether the potential test is taken during the month in which it is received by the RRC or any prior month.

b. The initial potential test form for any new completion or recompletion must be accompanied by the well record.

3. Maximum gas-oil ratio: See 16 TAC §3.49, relating to Gas-Oil Ratio.

(a) Provision for limiting gas-oil ratio: 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.

(a) 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.

$$Q = A\left(r1 - r2 + \frac{199.3\ PrB}{TrZ}\right)$$

Where:

Q = Gas well allowable, cubic feet/ day at 14.65 PSIA and 60º F.

A = Top oil well allowable, barrels per day at 60º F.

r1 = Permissible gas-oil ratio applicable to reservoir, cubic feet at 14.65 PSIA and 60o F. per barrel at 60° F.

r2 = Cubic feet of gas dissolved in one (1) barrel of oil at average reservoir conditions, cubic feet at 14.65 PSIA and 60º F. per barrel at 60º 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.

$$Q = \frac{A^{(r1 - r2 + 199.3\ PrB/TrZ)}}{1 - r2/r3 + 199.3\ PrB/\ r3\ TrZ}$$

Where:

R3 = Gas-Oil ratio of gas well, cubic feet at 14.65 PSIA and 60ºF per barrel at 60ºF. 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 calculated gas well allowable;

(B) the well's capability as determined by §3.31(e) (Gas Reservoirs and Gas Well Allowable); 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 RRC 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) The formulas shall 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) (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.

4. Bottom-hole pressure test reports required:

a. Periodical bottom-hole pressure surveys: Upon request.

5. Commingling oil in common facilities: see 16 TAC §3.26, relating to 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 used under TNRC 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 RRC.

(2) All oil and any other liquid hydrocarbons as and when produced shall be adequately measured pursuant to paragraphs (3) and (4) below 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 (Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering) and the full well stream is measured, with each completion being separately measured, before the gas 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 API Manual of Petroleum Measurement Standards, Chapter 6.1 or another method approved by the RRC or its delegate, is being used to effect custody transfer.

(4) For RRC 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 API or American Gas Association for measuring oil or gas, as applicable, or approved by the Director of the Oil and Gas Division as an accurate measurement technology.

(b) In order to prevent waste, to promote conservation or to protect correlative rights, RRC may approve surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same RRC-designated reservoir or from one or more tracts of land producing from different RRC-designated reservoirs as follows:

(1) Administrative approval. Upon written application, the RRC may grant approval for surface commingling administratively when any one of the following conditions is met:

(A) The tracts or RRC-designated reservoirs have identical working interest and royalty interest ownership in identical percentages and therefore there is no commingling of separate interests;

(B) Production from each tract and each RRC-designated reservoir is separately measured and therefore there is no commingling of separate interests; or

(C) When the tracts or RRC-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and the RRC 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: (i) a method of allocating production to ensure the protection of correlative rights, in accordance with paragraph (3) of this subsection; and (ii) 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 (iii) 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 RRC's notice of application has been published once a week for four 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 RRC-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, the applicant may request a hearing on the application. RRC must give notice of the hearing to all working interest and royalty interest owners. RRC may permit the commingling if the applicant demonstrates that the proposed commingling will protect the rights of all interest owners and will prevent waste, promote conservation or protect correlative rights.

(3) Reasonable allocation required. The applicant must demonstrate 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.

(A) In the absence of contrary information, such as indications of material fluctuations in the monthly production volume of a well proposed for commingling, RRC will presume that allocation based on the daily production rate for each well as determined and reported to RRC 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 RRC in accordance with §§3.28, 3.52, 3.53, and 3.55 (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).

(B) Operators may test commingled wells annually after approval by RRC 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.

(C) Nothing in this section prohibits allocations based on more frequent well tests than the semi-annual well test set out in subparagraph (A) of this paragraph. 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.

(D) 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.

(4) Additional notice required. In addition to giving notice to the persons entitled to notice under paragraph (1)(C) of this subsection, an applicant for a surface commingling exception must give notice of the application to the operator of each tract adjacent to one or more of the tracts proposed for commingling that has one or more wells producing from the same RRC-designated reservoir as any well proposed for commingling if: (A) any one of the wells proposed for commingling produces from a RRC-designated reservoir for which special field rules have been adopted; or (B) any one of the wells proposed for commingling produces from multiple RRC-designated reservoirs, unless: (i) an exception to §3.10 (Restriction

of Production of Oil and Gas from Different Strata) has been obtained for production from the well; or (ii) the applicant continues to separately measure production from each different RRC-designated reservoir produced from the same wellbore.

(c) 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.

(d) Oil gravity tests and reports. 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. (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 RRC-required production reports, the operator may, at his 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:

> (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 RRC 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 face of his 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 RRC 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.

6. Measurement involving meters:

§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.

7. Production reports:

    a. By lease: Yes, oil wells.

    b. By well: Gas wells.

    c. Time limit: Producers are required to file Form PR monthly for all crude oil, casinghead gas, gas well gas, and condensate produced. Form PR is filed for oil wells for any month there is production, whether the production was prior to or after initial completion, and/or for stock on hand. Form PR is filed for gas wells from the month of the completion date. For recompletions Form PR is filed from the recompletion date on both oil and gas wells. On reclassified wells, Form PR is due from the month of test as shown on Form G-1 and/or Form W-2. The original monthly Form PR must be filed with the RRC's Austin Office on or before the last day of the month following the month covered by the Form PR report.

XVI. Gas Production

1. Definition of a gas well: 16 TAC §3.79(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 CF 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.

2. Pressure base ________ psia @ ________degrees F.

3. Initial potential tests: See [16 TAC §3.28](), relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported.

   a. Time interval:

      (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 RRC within 90 days of completion of the well. The test shall be performed in accordance with the RRC's publication, Back Pressure Test for Natural Gas Wells, State of Texas, or other test procedure approved in advance by the RRC and shall be reported on the RRC'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 RRC 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 results on the RRC's prescribed form no later than 90 days after completion of the well. If a 72-hour one-point back pressures 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.

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 recorded. 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. 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 RRC 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 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.

4. Bottom-hole pressure test reports required:

    a. Periodical bottom-hole pressure surveys: 16 TAC §3.41 Application for New Oil or Gas Field Designation and/or Allowable. Requires a bottom-hole pressure for oil wells before the RRC will assign a new field designation and/or discovery allowable. The 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.

5. Commingling of gas in common facilities: See 16 TAC §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 must report the volume produced from each completion to RRC. For commission purposes, the measurement requirements of this rule are satisfied by the use of coriolis or turbine meters or any other measurement device or technology that conforms, as of the time of installation, to standards been established by the American Petroleum Institute (API) or the American Gas Association (AGA) for measuring oil or gas, as applicable, or that has been approved by the Director of the Oil and Gas Division as an accurate measurement technology. Exceptions to this provision may be granted by RRC 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, must be measured before the gas leaves the lease, and the producer must report the volume produced to RRC. Exceptions to this provision may be granted by RRC upon written application.

c. All casinghead gas produced in this state which in 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 RRC upon written application.

d. Releases and production of gas at a volume or daily flow rate ("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 RRC or charged against lease allowable production.

e. In order to prevent waste, to promote conservation or to protect correlative rights, 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(b).

f. In reporting gas well production, the full-well stream gas must 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 shall be measured and allocated to each individual lease based on semiannual testes conducted on full well stream lease production.

i. For the purposes of this rule, “measured" shall mean a determination of gas volume in accordance with this rule and other rules of RRC, including accurate estimates of unmetered gas volumes released into the air or used as fuel.

6. Measurement involving meters: See above.

7. Production reports:

   a. By lease: For oil wells.

   b. By well: For gas wells.

   c. Time limits: [16 TAC §3.54] (Gas Reports Required)

      i. (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.

      ii. (b) Pressure maintenance and repressuring plant report.

         1. (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 represurring an oil or gas reservoir, but 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. (2) Pressure maintenance.

            a. (A) The operator of each pressure-maintenance or repressuring plant shall file the report although no liquid hydrocarbons are recovered.

b. (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 if 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.

iii. (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.

iv. (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.

v. (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 well by the commission, except those expressly exempted by the commission shall file a report on the required form.