AMENDMENTS TO RULE 13, CASING, CEMENTING, DRILLING, WELL CONTROL, AND COMPLETION REQUIREMENTS

To be Effective
January 1, 2014

On May 24, 2013, the Railroad Commission of Texas (Commission) adopted amendments to §3.13, relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements.

The adopted amendments:
- implement certain provisions of House Bill 2694 (82nd Legislature, Reg. Sess. 2011)
- more clearly outline the requirements for all wells
- consolidate the requirements for well control and blow-out preventers, and
- update the requirements for drilling, casing, cementing, and fracture stimulation.

The adopted effective date of these amendments is January 1, 2014, to allow operators time to become familiar with the new requirements for wells to be drilled and to allow the Commission time to develop and advise operators of the lists of potential flow zones and zones with corrosive formation fluids. Operators will be subject to these amendments for any wells that will be spudded on or after January 1, 2014. Wells spudded before January 1, 2014, will be subject to the current requirements of §3.13 in effect through December 31, 2013.

The Commission's requirements in §3.13 for drilling, casing and cementing oil and gas wells in Texas have been proven effective over time. The adopted amendments specifically update those existing requirements to address areas in which the risks to groundwater may be higher. These new requirements codify many best management practices that already are being implemented by most operators.

§3.13(a)(1) INTENT
- Clearly states the intent of the rule
- Requires isolation of potential flow zones and zones with corrosive formation fluids.

§3.13(a)(2) DEFINITIONS.
- **Amended definitions:**

  “Zone of critical cement" amended to clarify that, for intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or to the top of the highest proposed productive zone, whichever is less.

  "Protection depth" amended to reflect transfer from the Texas Commission on Environmental Quality (TCEQ) to the Commission duties relating to the protection of groundwater resources from oil and gas associated activities, effective September 1, 2011.

- **New definitions**

  "Hydraulic fracturing treatment" defined as a completion process involving the treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas.

  "Minimum separation well" defined as a well in which hydraulic fracturing treatments will be conducted in which:

  (i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet;

  (ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or

  (iii) the director has determined is in a structurally complex geologic setting.

  "Potential flow zone" defined to mean a zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or oil, gas, or geothermal resources. The Commission will maintain a list of known zones by district and county that are considered potential flow zones and make this information available to all operators. The

Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

"Zone with corrosive formation fluids" defined to mean any zone designated by the director or identified by the operator using available data containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field. The Commission will maintain a list of known zones by district and county that are considered zones with corrosive formation fluids, and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

§3.13(a)(3) Wellbore diameters

- Requires that the diameter of the wellbore in which surface casing will be set and cemented must be at least one and one-half (1.50) inches greater than the nominal outside diameter of casing to be installed
- For subsequent casing strings, the diameter of each section of the wellbore for which casing will be set and cemented must be at least one (1.0) inch greater than the nominal outside diameter of the casing string to be installed, unless otherwise approved by the district director.
- Allows the district director to grant approvals on an area basis from the requirement for subsequent casing strings.
- Does not apply to re-entries, liners, and expandable casing.

§3.13(a)(4) Casing and cementing

- Casing must be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, and all formations permitted for injection under §3.9 at the time the well is completed, or cemented immediately above all formations permitted for injection under §3.46 at the time the well is completed, in a well within ¼ mile of the proposed well location, as follows:

  (i) If the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the permitted formations;

  (ii) If the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, across and extending 250 feet (measured depth) above the permitted formations;

  (iii) if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the permitted formations;

  (iv) across and extending at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or

  (v) as otherwise approved by the district director.
- Cement slurry must be designed to control annular gas migration consistent with the standards in, or equivalent to the standards in, *API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction*.

§3.13(a)(5) Casing testing before drillout.

- For surface and intermediate strings of casing, before drilling the cement plug, the operator must test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot. The maximum test pressure required, however, unless otherwise ordered by the Commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. The operator must notify the district director of a failed test. In the event of a pressure test failure, completion operations may not re-commence until the district director approves a remediation plan, the operator successfully implements the plan, and the operator conducts a successful pressure test.

§3.13(a)(6) Well control

- Consolidates all well control and blowout preventer (BOP) requirements.
- Amends the existing language to update the requirements for the makeup of BOP systems.
- Requires all hole intervals drilled prior to reaching the base of protected water be drilled with air, fresh water, or a fresh water based drilling fluid and prohibit the use of oil based drilling fluid in drilling until the casing has been set and cemented to the protection depth.
- Allows an annular preventer to be used in lieu of casing/pipe rams or variable bore rams when running production casing, provided the expected shut-in surface pressures would not exceed the tested pressure rating of the annular preventer;

§3.13(a)(7) Additional requirements for wells on which hydraulic fracturing treatment(s) will be conducted.

- Requires that all casing strings (or fracture tubing) installed in a well that will be subjected to hydraulic fracturing treatments (HFT(s)) have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing string will be subjected.
- Operator must pressure test the casing (or fracture tubing) on which the pressure will be exerted during HFTs to at least the maximum pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve must be tested to 80% of actuation pressure for a minimum time period of five (5) minutes and a surface pressure loss of greater than 10% of the initial test pressure is considered a failed test. The casing to be pressure tested is the casing string from the wellhead to at least the depth of the top of cement behind the casing being tested. The district director must be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no HFT(s) 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).
- Requires that operators monitor all annuli during HFT(s) and suspend fracturing operations if pressures deviates above those anticipated increases caused by pressure or thermal transfer.
- Adds requirements for "minimum separation wells". Operator must: (1) cement the production casing using sufficient cement to fill the annular space outside the casing string from the casing shoe to the ground surface or to the bottom of the cellar; (2) cement the production casing string from the shoe up to a point at least 200 feet above the shoe of the next shallower casing string set and cemented in the well; (3) pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatments and notify the district director within 24 hours of a failed test; (4) run a cement evaluation tool to assess radial cement integrity and placement behind the production casing string. The rule allows for approval of an exemption from the district director after five successful wells.

§3.13(b) Casing and cementing requirements for land wells and bay wells

- Requires district director approval of any proposal to set surface casing to a depth of 3,500 feet or greater. The request must be written and must specify how the operator plans to maintain well control during drilling, ensure successful circulation and adequate bonding of cement, and, if necessary, prevent upward migration of deeper formation fluids into protected water. Allows the district director to grant approvals on an area basis.
- Deletes obsolete language regarding field rules that specify surface casing requirements. The depth to which all surface casing must be set will be determined by the Commission's Groundwater Advisory Unit.
- Free water content of the cement must be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. The free water separation may average no more than two milliliters (rather than 6 mil) per 250 milliliters of cement tested in accordance with the current API RP 10B inside the zone of critical cement or no more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement.
- Updates the reference and to allow equipment and procedures equivalent to those in API RP 10B-2 and references the API recommended practices and specifications for various types of centralizers and to allow equivalent practices and specifications.
- Clarifies that alternative surface casing programs may be requested. Requires district director to deny the request if the operator has not demonstrated that the alternative casing plan will achieve the intent of the rule.
- Requires a multi-stage tool to be set at least 100 feet, rather than 50 feet, below the protection depth.
- Requires that, if the surface casing string is exposed to more than 360 rotating hours, the operator verify the integrity of the casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director. If a mechanical integrity test is conducted, the appropriate district office must be notified at least eight hours before the test is conducted. Operator must use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director. Surface casing must be tested at a pump pressure in pounds per square inch (psi), calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. Requires notification of the appropriate district office within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan and successfully re-tests the surface casing.

(b)(2) Intermediate casing requirements for land wells and bay wells.

- Requires cementing of intermediate casing above any potential flow zone or zone with corrosive formation fluids. If the top of cement is determined through calculation, cement must be placed from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; if the top of cement is determined through performance of a temperature survey, cement must be placed from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; if the top of cement is determined through performance of a cement evaluation log, cement must be placed from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or cement must be placed to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or as otherwise approved by the district director.
- Requires that the calculated or measured top of cement be indicated on the appropriate completion form.
- Allows the use of a multi-stage tool to isolate potential flow zones and/or zones with corrosive formation fluids.

(b)(3) Production casing requirements for land wells and bay wells."

- Requires that the operator provide additional centralization to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.
- Requires that any potential flow zone or zone with corrosive formation fluids be cemented in a manner that effectively seals off those zones.
- Requires that a float collar or other means to stop the cement plug be inserted in the casing string above the shoe.
- Requires that cement be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.
- In the event that the distance from the casing shoe to the top of the shallowest productive zone makes cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive zones, and prevent fluid migration to or from such strata within the wellbore.
- Requires that the calculated or measured top of cement must be indicated on the completion report.
- Clarifies language regarding liners
- Requires that the tubing be at a point no higher than 100 feet above the kickoff point in a deviated or horizontal well.
- The Commission will authorize an alternate program requesting a temporary exception to the requirement for tubing in a flowing oil well only on an individual well basis.

§3.13(c) Casing, cementing, drilling, and completion requirements for offshore wells

- Requires verification of surface casing integrity after drillout if the surface casing string is exposed to more than 360 rotating hours.
- Requires isolation of productive zones as well as potential flow zones and/or zones with corrosive formation fluids.

§3.13(d) Exceptions or alternate programs

- Allows the director to administratively grant an exception or approve an alternate casing/tubing program required by this section provided that the intent of the rule and additional requirements are met.
- Request for an exception or alternate casing/tubing program must be accompanied by the fee required by Rule 78.
- An administrative exception for tubing must not exceed a period of 180 days. A request for an exception for tubing beyond 180 days would require a Commission order.