

**MODEL REGULATORY
FRAMEWORK
FOR
HYDRAULICALLY FRACTURED
HYDROCARBON PRODUCTION WELLS
(2019)**

Table of Contents

	<u>Page</u>
INTRODUCTION	1
ARTICLE I - DEFINITIONS	2
ARTICLE II - WELL PLANNING (PERMITTING)	7
2.1 Scope of Article.....	7
2.2 Permitting Process.....	7
2.3 Permit Application Requirements.....	8
2.4 Term of Permit	11
2.5 Well Database.	11
ARTICLE III - WELL OPERATIONS – DRILLING, CASING AND CEMENTING	12
3.1 Scope of Article.....	12
3.2 General Requirements.....	12
3.3 Conductor Casing.....	17
3.4 Surface Casing.....	18
3.5 Intermediate Casing.....	19
3.6 Production Casing.....	22
3.7 Minimum Separation Wells.....	23
3.8 Approved Cementers.....	24
3.9 Inclination and Directional Surveys.....	24
ARTICLE IV - WELL OPERATIONS – COMPLETION, HYDRAULIC FRACTURING AND SUBSEQUENT WELL OPERATIONS	30
4.1 Scope of Article.....	30
4.2 General Well Control Guidelines	30
4.32 Before Hydraulic Fracturing Treatment.....	311
4.4 During Hydraulic Fracturing Treatment.....	33
4.5 Post-Treatment Report.....	34
4.6 Approved Hydraulic Fracturing, Perforation and/or Logging Contractors.....	36
ARTICLE V - WELL OPERATIONS – PRODUCTION AND WELL MONITORING.....	37
5.1 Scope of Article.....	37
5.2 Production and Well Monitoring.....	37
ARTICLE VI - PLUGGING AND WELL ABANDONMENT.....	39
6.1 Scope of Article.....	39
6.2 Application to Plug an Abandoned Well.....	39
6.3 Commencement of Plugging Operations, Extensions, and Testing.....	40

6.4	Designated Operator Responsible for Proper Plugging.	43
6.5	General Plugging Requirements.....	43
6.6	Plugging Requirements for Wells with Surface Casing.....	46
6.7	Plugging Requirements for Wells with Intermediate Casing.....	46
6.8	Plugging Requirements for Wells with Production Casing.	47
6.9	Plugging Requirements for Wells with Screen or Liner.	47
6.10	Plugging Requirements for Wells with Formation Pressure Problems.....	47
6.11	Plugging Horizontal Wells.....	48
6.12	Plugging of Minimum Separation Wells.....	48
6.13	Marking the Location of a Plugged Well.....	48
6.14	Approved Cementers.....	48

INTRODUCTION TO MODEL REGULATORY FRAMEWORK (2019)

1. **Scope of Model Regulatory Framework.** This Model Regulatory Framework for Hydraulically Fractured Hydrocarbon Production Wells (the “MRF”) is intended to assist state governments in implementing a distinct regulatory regime governing subsurface aspects of the drilling, casing, cementing, hydraulic fracturing stimulation, completion and production of onshore hydrocarbon exploration and production wells. The MRF addresses certain regulatory and operational issues pertaining to wellhead control and subsurface wells that are critical to ensuring the integrity of a hydraulically fractured hydrocarbon production well throughout its full life-cycle, beginning with the permitting process and ending with plugging and abandonment. The MRF is intended to apply to all onshore hydraulically fractured hydrocarbon exploration and production wells, regardless of depth or trajectory, but is explicitly **not** intended to govern and does **not** address (i) any aspect of injection wells, storage wells or any other type of wells that may also be stimulated via hydraulic fracturing; (ii) any surface issues such as water use, impoundments, spill control, interagency coordination, surface containment of any well return fluids (including produced fluids generated during flowback, swabbing or other processes), or the off-site transport, recycling or disposal of well return fluids or (iii) ancillary topics such as groundwater sampling, chemical disclosure and induced seismicity. In addition, certain special considerations relating to the development of coalbed methane resources are not covered by the MRF.

2. **Purpose of Model Regulatory Framework.** The MRF is based on numerous “best-in-class” state rules and regulations, and incorporates industry best practices with regard to safety, efficiency and environmental protection. The MRF is meant to give state governments a road-map which can be used to implement hydraulic fracturing regulation that: (i) utilizes the structure of currently-effective state laws and regulations; (ii) mandates the use of effective operational industry practices; (iii) encourages technological advances and innovation in order to continually improve industry practices; and (iv) aims to ensure the protection of human health and safety and the environment. Articles I through VI of the MRF contain the substance of the MRF’s requirements, and are chronologically organized based on the life-cycle of a hydraulically fractured hydrocarbon well. These are:

- (a) ARTICLE I – Definitions
- (b) ARTICLE II – Well Planning (Permitting);
- (c) ARTICLE III – Well Operations – Drilling, Casing and Cementing;
- (d) ARTICLE IV – Well Operations – Completion, Hydraulic Fracturing and Subsequent Well Operations;
- (e) ARTICLE V – Well Operations – Production and Well Monitoring; and
- (f) ARTICLE VI – Plugging and Well Abandonment.

3. **Utilizing the Model Regulatory Framework.** It is important to note that while the MRF is written in the form of a rule, it is not meant to be an exhaustive scheme to be adopted directly, but instead is a working structure that sets forth key substantive components for effective regulation with regard to the topics and operations covered herein. The reason for this structure is to allow state governments and regulators adequate flexibility in the manner in which they are able to integrate the substantive provisions of the MRF into existing state law. Accordingly, it is expected that in implementing the MRF, state regulators may utilize different terminology, add or expound upon certain procedural requirements, or otherwise deviate from the MRF in certain non-substantive aspects. It is also recognized that in the design of a regulatory schema, states will adapt or modify standards to conform with state law, and to address a variety of factors, including unique aspects of geology and hydrology, natural resource conservation, drilling practices, petroleum reservoir characteristics and fluid properties, the history of incidents and failures, and definitions of protected groundwater. In implementing the MRF, due consideration should be given to encouraging operators to continuously pursue technological advancements and innovative solutions to better achieve the goals of the MRF. Similarly, the MRF itself may be adjusted from time to time as technologies and practices evolve. The 2019 MRF was developed by Environmental Defense Fund and number of independent technical experts. Suggested changes are welcome at mrf@edf.org.

ARTICLE I

DEFINITIONS

As used in the MRF, the following terms shall have the meanings ascribed to them below, unless the context clearly indicates otherwise:

1.1 “Active operation” shall mean regular and continuing activities related to the exploration, development or production of hydrocarbons for which the operator has all necessary permits.

1.2 “Annular flow” shall mean the flow of formation fluids (liquids and/or gases) from the formation into a space or pathway in an annulus within a well.

1.3 “Annular overpressurization” shall mean the wellbore condition that occurs when (i) fluids in the annulus between the surface casing and the intermediate/production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the surface casing shoe or (ii) fluids in the annulus between any intermediate casing (if intermediate casing is set) and the production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the intermediate casing shoe.

1.4 “Annulus” shall mean the space between the borehole and a casing string or between two casing strings in a well, where fluid can flow.

1.5 “Area of investigation” shall mean (i) with respect to a vertical well or the vertical portion of a horizontal well, a circular area formed by projecting a radius the required distance from the center of the well and (ii) with respect to the horizontal portion of a horizontal well, the combination of (a) a rectangular area formed by projecting a line the required distance perpendicular to, and on both sides of, the entire perforated section of the horizontal borehole plus (b) two semi-circular areas, the first formed by projecting a radius the required distance from the beginning point of the perforated section of the horizontal borehole, and the second formed by projecting a radius the required distance from the ending point of the perforated section of the horizontal borehole.

1.6 “Barrier” shall mean pressure- and flow-containing system, or practice(s) that contributes to well integrity by preventing the unintended communication of pressure and the unintended flow of fluid (liquid and/or gas) from one formation to another, or to the surface.

1.7 “Base Fluid” shall mean any fluid type used in a particular hydraulic fracturing treatment, including, but not limited to, water (including surface water, groundwater, produced water and recycled water) or nitrogen gas and foam fluids, and hydrocarbon gas.

1.8 “Bond” shall mean a surety instrument issued:

- (i) on a [STATE REGULATOR] approved form;
- (ii) by and drawn on a third party corporate surety authorized under [STATE] law to issue surety bonds in [STATE]; and
- (iii) renewed and continued in effect until the conditions of the bond have been met or its release is approved by [STATE REGULATOR].

1.9 “Completion” shall mean the collective operational activities that are conducted following drilling operations to prepare a well for production, including, but not limited to, installation of surface and downhole equipment in the wellbore, perforating, testing and well stimulation to facilitate hydrocarbon production.

1.10 “Confining layer” shall mean that portion of an intervening zone that has sufficient areal extent and integrity to act as an effective impermeable barrier to the vertical migration of gases or other fluids into any strata or zones that contain protected water.

1.11 “Corrosive zone” shall mean any zone designated by [STATE REGULATOR] 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.

1.12 “Delinquent inactive well” shall mean an unplugged well that (i) has had no reported production, disposal, injection, or other permitted activity for a period of greater than 180 days, or other term defined by [STATE REGULATOR], (ii) does not have an approved application

for suspended service from [STATE REGULATOR], and (iii) for which, after notice and opportunity for hearing, [STATE REGULATOR] has not extended the plugging deadline.

1.13 “Directional deviation” shall mean the intentional deviation of a well from vertical in a predetermined compass direction.

1.14 “Funnel viscosity” shall mean viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

1.15 “Good faith claim” shall mean a factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid hydrocarbon lease or a recorded deed conveying a fee interest in the mineral estate.

1.16 “HF service company” shall mean a person or entity that performs hydraulic fracturing treatments in [STATE] for an operator.

1.17 “Health professional” shall mean a physician, physician’s assistant, industrial hygienist, toxicologist, epidemiologist, nurse or nurse practitioner providing medical or other health services to a person potentially exposed to a chemical, or an emergency responder who is responding to an emergency where chemicals may be present.

1.18 “Hydraulic fracturing” or “Hydraulic fracturing treatment” shall mean the action of stimulating a well by the pumping of fluids of any nature (which may contain proppant such as sand or man-made material) under pressure in order to create and maintain artificial fractures in the formation for the purpose of improving the capacity to produce the flow of hydrocarbons up the well; provided, however, the term “hydraulic fracturing” shall not include any activities or operations that are not designed to generate new fractures in the zone(s) of interest.

1.19 “Hydraulic fracturing fluid” shall mean the fluid used to perform a particular hydraulic fracturing treatment and includes the applicable base fluid and all additives.

1.20 “Hydrocarbon” shall mean a naturally occurring organic compound comprised of hydrogen and carbon and may include oil, gas and other liquid and gaseous hydrocarbons.

1.21 “Hydrocarbon strata” shall refer to any stratum encountered in a well that contains hydrocarbons.

1.22 “Impacted strata” shall mean (i) the productive horizon that is to be stimulated with a hydraulic fracturing treatment and (ii) all strata that are immediately adjacent to such productive horizon and are within the estimated or calculated fracture height for such hydraulic fracturing treatment.

1.23 “Intervening zone” shall refer to those geological formations (or part of a formation) located between the top boundary of the productive horizon that is being hydraulically fractured and the base of the deepest stratum or zone that contains protected water.

1.24 “Limited intervening zone” shall mean an intervening zone that (i) is less than 1,000 vertical feet thick, or (ii) is more than 1,000 vertical feet thick, but which [STATE REGULATOR] determines, based on the lithologic, geomechanical or other properties of the formations that comprise the intervening zone, may not contain an adequate confining layer or is in a structurally complex geologic setting with known faults that extend through the intervening zone and are likely to be transmissive. Notwithstanding the foregoing, an intervening zone less than 1,000 vertical feet thick may be excluded from classification as a “limited intervening zone” if the [STATE REGULATOR] determines that such intervening zone contains an adequate confining layer.¹

1.25 “Liner” shall mean a casing string that does not extend to the top of the well or to the wellhead. Liners are anchored or suspended from inside the previous casing string using a liner hanger. The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

1.26 “Logging” shall mean to run any of a number of instruments into a well to measure the mechanical or physical properties of the well, including but not limited to, the condition of the casing and/or cement, or the pressure, temperature, fluid, mechanical or petrophysical properties of the geological formations immediately adjacent to the wellbore.

1.27 “Maximum anticipated pressure” shall mean the maximum pressures reasonably expected to be exerted upon a casing string and related wellhead and control equipment. In calculating maximum anticipated surface pressures, consideration shall be given to: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions.

1.28 “Minimum separation well” shall mean a hydraulically fractured well with a limited intervening zone.

1.29 “Operator” shall mean the party designated to conduct operations on a well, and subject to regulation by [STATE] as an operator.

1.30 “Perforating” shall mean to penetrate the casing wall and cement of a wellbore in order to provide holes through which hydraulic fracturing fluids and proppant may enter the formation and formation fluids may enter the wellbore.

1.31 “Permit application” shall mean a formal request by an operator made with [STATE REGULATOR] for a permit to drill, deepen, plug back, reenter, or refracture any well for the purpose of exploring for, developing and producing hydrocarbons through the use of hydraulic fracturing operations.

¹ For technical justification of the selection of 1,000 vertical feet as the default demarcation point for close proximity wells, please see “*Hydraulic Fracture-Height Growth, Real Data*” (SPE 145949) by Kevin Fisher and Norm Warpinski (2011); “*Hydraulic fractures: How far can they go?*” by Richard Davies, Simon Mathias, Jennifer Moss, Steinar Hustoft and Leo Newport (2012); and “*Hydraulic fracture height limits and fault interactions in tight oil and gas formations*” (Geophysical Research Letters Vol. 40) by Samuel Flewelling, Matthew Tymchak and Norm Warpinski (2013).

1.32 “Productive horizon” shall mean any hydrocarbon strata determined to contain commercial quantities of hydrocarbons.

1.33 “Proppant” shall mean sand or another natural or man-made material that is used in a hydraulic fracturing treatment to prevent artificially created or enhanced fractures from closing once the treatment is completed.

1.34 “Protected water” shall mean water that is classified or identified by [STATE REGULATOR] as being of sufficient quality and quantity to merit protection as a current or potential future source of water.

1.35 “Protection depth” shall mean the depth to which protected water must be protected, as determined by [STATE REGULATOR], which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain protected water.

1.36 “Random deviation” shall mean the intentional deviation of a well without regard to compass direction to (a) straighten a hole which has become crooked in the normal course of drilling, or (b) sidetrack a portion of a hole because of mechanical difficulty in drilling. Random deviation does not include intentional side-tracks for geologic and/or reservoir related conditions.

1.37 “Refracture” shall mean the action of restimulating a well through a hydraulic fracturing treatment at a later date after the initial hydraulic fracturing treatment and some period of producing the well.

1.38 “Related piping” shall mean the surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term “related piping” does not include lines, such as flow lines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

1.39 “Reported production” shall mean those quantities of hydrocarbon production that are reported to [STATE REGULATOR].

1.40 “Required distance” shall mean (i) 1,320 feet or (ii) such other greater or lesser distance as [STATE REGULATOR] may specify in the event [STATE REGULATOR] determines that regional or local conditions justify a larger or smaller area of investigation.

1.41 “Source of protected water” shall mean any groundwater or surface water which is used or otherwise classified by [STATE REGULATOR] as a source of protected water.

1.42 “Stand under pressure” shall mean to leave the hydrostatic column pressure in a well acting as the natural force without adding any external pump pressure.

1.43 “[STATE REGULATOR]” shall not have fixed meaning, but instead shall be a “place-holder” that refers to the applicable state regulatory body, authority, office or duly authorized person, given the context.

1.44 “Well” shall mean a hydrocarbon production well that will be hydraulically fractured, unless the context clearly indicates otherwise.

1.45 “Zone of critical cement” shall mean (i) for surface casing strings greater than 300 feet in length, the bottom 20% of the casing string, but in no event shall it be more than 1,000 feet or less than 300 feet, (ii) for surface casing strings of 300 feet or less in length, the zone of critical cement shall extend to the land surface, and (iii) for intermediate and production casings, the bottom 20% of the casing string or not less than 300 feet above the casing shoe or proposed productive horizon.

ARTICLE II

WELL PLANNING (PERMITTING)

2.1 **Scope of Article.** This Article governs the process whereby an operator must apply for and obtain from [STATE REGULATOR] a permit to drill, deepen, plug back, reenter, complete, recomplete or refracture a well for the purpose of exploring for, developing and producing hydrocarbons from oil and gas bearing strata through the use of hydraulic fracturing operations in a manner that prevents contamination of protected water and protects human health and safety and the environment.

2.2 **Permitting Process.**

(a) A permit application shall be made pursuant to and in accordance with any and all applicable laws, rules and regulations of [STATE REGULATOR] governing the permitting of hydrocarbon wells in the state of [STATE], and filed with [STATE REGULATOR] on a form approved by [STATE REGULATOR]. Each permit application shall be accompanied by all applicable information, forms and certifications more particularly described in Section 2.3 below so that [STATE REGULATOR] may effectively assess whether the well proposed in the permit application meets the requirements of this rule for preventing contamination of protected water and for protecting human health and safety and the environment.

(b) Operations for the drilling, deepening, plugging back, reentering, completing, recompleting or refracturing of a well for the purpose of exploring for, developing and producing hydrocarbons through the use of hydraulic fracturing operations shall not commence until the permit has been granted by [STATE REGULATOR]. A permit shall be granted to operator upon [STATE REGULATOR’s] review and approval of a complete permit application meeting the requirements of Section 2.3 below.

2.3 **Permit Application Requirements.**

(a) A permit application shall provide a well plan that contains the following information:

- (i) the operator name;
- (ii) the lease, pooled unit or unitized tract name;
- (iii) the lease, pooled unit or unitized tract number or gas identification number;
- (iv) well number;
- (v) county, parish or other appropriate geographic subdivision;
- (vi) field name
- (vii) expected well type (oil / gas)

(viii) type of well work (if existing well, include a wellbore schematic with information from (ix) and (x) below and current completion information.)

(ix) the identification and anticipated true vertical depth(s) to the top of all formation intervals intended to be tested and/or hydraulically fractured, the estimated depth to the top and base of protected water, and, if known, any zone requiring isolation;

(x) a casing and cementing plan that includes casing dimensions and strengths (e.g. internal yield, collapse, joint yield strength), cement type, yield and compressive strength, and cement top;

(xi) a plat showing the well location as described in 2.3(c) and (d),

(xii) a statement as to how the well location would comply with any applicable spacing rule and how the surface location would comply with any applicable set-back rules to structures, water supplies and public sites, such as schools and hospitals.

(xiii) a statement indicating that the well will be hydraulically fractured, together with a list of the following information:

- (a) the type of base fluid to be used;
- (b) the estimated total volume of hydraulic fracturing fluid and proppant to be used;
- (c) the maximum anticipated pumping pressure;

(d) the anticipated surface treating pressure range for the hydraulic fracturing treatment; and

(e) the estimated or calculated fracture length and height anticipated as a result of the hydraulic fracturing treatment;

(xiv) a general description of the anticipated source or sources of base fluid to be used for hydraulic fracturing operations;

(xv) a statement describing the anticipated method(s) for handling, recycling (if applicable) and/or disposing of all flowback water and produced water from the well;

(xvi) a statement that, based on operator's analysis of the intervening zone, including an evaluation of existing wells of record or known transmissive faults and fractures that penetrate the impacted strata within the area of investigation, the intervening zone contains an adequate confining layer and no such well or fault or fracture may be a conduit for movement of fluids into a source of protected water. The location of all wells and known transmissive faults and fractures evaluated pursuant to this subpart (xvi) shall be identified on the plat described in Section 2.3(c) below;

(xvii) a statement whether or not the well will be a minimum separation well;

(xviii) an explanation of the steps to be taken to comply with the requirements for minimum separation wells in Section 4.3(f) and (g); and

(xix) such other information as [STATE REGULATOR] may require.

(b) With each permit application or materially amended permit application, the applicant shall submit to [STATE REGULATOR] a permit processing fee and a demonstration of financial security that complies with the applicable financial security requirements of [STATE REGULATOR]. A permit application shall not be deemed complete without the payment to [STATE REGULATOR] of the applicable permit processing fee.

(c) A permit application shall be accompanied by a legible, accurate plat, with a scale of one inch equals 500 feet or such other scale as determined by [STATE REGULATOR]. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or unitized tract, including all tracts being pooled or unitized. The boundary of the lease, pooled unit or unitized tract shall be outlined on the plat using either a heavy line or crosshatching. If necessary to show the entire lease, pooled unit or unitized tract, the scale may be one inch equals 2,000 feet or such other scale as determined by [STATE REGULATOR]. Plats for subsequent wells on a lease, pooled unit or unitized tract shall show at least the lease, pooled unit or unitized tract boundary line nearest the proposed location and the nearest permanent geographic subdivision boundary. [STATE REGULATOR] may approve plats with other scales upon request. Specific inclination and directional survey requirements for each well are found in Section 3.9. The plat shall include the following:

- (i) the surface location of the proposed drilling site, the proposed horizontal well and the proposed path, penetration point and terminus location for the well;
 - (ii) perpendicular lines providing the distance in feet from the two nearest non-parallel permanent geographic subdivision boundaries to the surface location;
 - (iii) perpendicular lines providing the distance in feet from two nearest non-parallel lease or unit boundary lines to the surface location;
 - (iv) a line providing the distance in feet from the surface location to the nearest point on the lease or unit 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;
 - (v) a line providing the distance in feet from the surface location to the nearest well identified by number either applied for, permitted, completed or abandoned in the same lease, pooled unit, or unitized tract and in the same field and reservoir;
 - (vi) the geographic location information in plane coordinates meeting [STATE] GPS standards;
 - (vii) a labeled scale bar;
 - (viii) northerly direction; and
 - (ix) the location of all wells evaluated pursuant to 2.3(a)(xvi).
- (d) For directional or horizontal wells, specific permit requirements and survey requirements are found in Section 3.9(h). The plat attached to the permit application shall contain the following additional information:
- (i) the lease, pooled unit, or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract;
 - (ii) the surface location of the proposed well, and the proposed path, penetration points, and terminus locations of all wells to be drilled in the wellbore;
 - (iii) two perpendicular lines from the nearest point on the lease line, pooled unit line, or any unleased interest in a tract of the pooled unit, depicting the distance(s) to:
 - (1) the penetration point(s); and
 - (2) the terminus location(s);

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey lines to the terminus location(s);

(v) a line providing the distance in feet from the closest point along the course(s) of the well(s) 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; and

(vi) lines from the nearest oil, gas, or oil and gas well, applied for, permitted or completed in the same lease or pooled unit and in the same field and reservoir depicting the distance to:

- (1) the penetration point(s);
- (2) the closest point along the course(s) of the well(s); and
- (3) the terminus location(s).

2.4 **Term of Permit.** Any permit to drill, deepen, plug back, reenter, or refracture granted by [STATE REGULATOR] shall expire no later than two years after the date of original approval.

2.5 **Well Database.**

(a) [STATE REGULATOR] shall be responsible for the creation and maintenance of a public database that depicts the official surface location, kick-off point, landing point and bottom-hole locations (including all lateral boreholes), as applicable; of all hydrocarbon, disposal, injection, water and geothermal wells constructed within the [STATE], and the then-current status of each such well (e.g., producing, temporarily abandoned, plugged and abandoned, etc.), as well as the depths of all protected water, potential flow zones and corrosive zones within the [STATE].

(b) [STATE REGULATOR] shall determine or approve the location-specific surface casing depth for the permitted well based upon a review of its database(s) or based upon a hydrologic map showing the depth of the lowermost aquifer containing protected water. In undeveloped areas where protected water depths are not well documented, an appropriate surface casing depth will be estimated by the [STATE REGULATOR], and the operator will be required to collect site-specific data (e.g. drilling rate changes associated with lithologic changes, cuttings, openhole logs and/or hydrological information) to verify the depth of protected water before setting surface casing.

ARTICLE III

WELL OPERATIONS – DRILLING, CASING AND CEMENTING

3.1 **Scope of Article.** It is the intent of all provisions of this Article that (i) all well casing shall meet appropriate API standards and be sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times, (ii) all zones containing protected water shall be isolated and sealed off to effectively prevent contamination or harm to any water therein, and (iii) all zones capable of causing annular flow that could negatively impact the quality of the cement and/or casing or result in annular overpressurization, and all zones containing corrosive fluids or gases, shall be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. This Article does not specifically address unique situations such as karsts, mines, voids or interaction with gas storage operations which are unique to specific geographic areas. [STATE REGULATOR] shall administer this Article consistent with this intent. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

3.2 **General Requirements.**

(a) All casing shall be steel or corrosion resistant alloy (CRA) casing, or other suitable casing material that has been hydrostatically pressure tested (e.g., a mill test) with an applied pressure that exceeds the maximum pressure to which the pipe will be subjected in the well by at least 20%. Any casing that will be utilized by the operator in conducting hydraulic fracturing operations shall meet API standards, including API Spec 5CT (Specifications for Casing and Tubing) and/or 5CRA (Specification for Corrosion Resistant Allow Seamless Tubes for Use as Casing, Tubing and Coupling Stock), and API casing specifications and recommended practices shall govern the design, manufacturing, testing and transportation of such casing (including compression, tension, collapse and burst resistance). New casing must be used for conductor casing, surface casing, and intermediate casing when used for water protection casing. If used casing is installed as production casing or intermediate casing (not serving as the water protection casing), it must pass a visual, hydro-test, corrosion, drift and wall thickness inspection, have no more than 10% wall loss, and meet API performance requirements for new casing as outlined in API Spec 5CT (Specification for Casing and Tubing). [STATE REGULATOR] may require additional casing strings to be installed to address site specific risks or hazards.

(b) Wellhead assemblies shall be used on all wells to maintain surface control of the well. Wellhead equipment, including associated fittings, flanges, and valves, shall conform to API 6A (Specification for Wellhead and Christmas Tree Equipment). Each component of the wellhead shall have a pressure rating at least 20% greater than the anticipated pressure to which the component might be exposed during the course of drilling, testing, completing or producing the well. All wellhead connections shall be assembled and tested prior to installation. Wells must be equipped to monitor all casing and annular pressures.

(c) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed and tested as soon as practicable, but no later than prior to drilling out of the surface casing. A diverter system shall be installed while drilling the surface

casing wellbore, unless waived by [STATE REGULATOR] based on prior drilling data that confirms shallow gas and other drilling hazards are not present. All well control equipment shall be constructed and capable of satisfying any accepted test which may be required by [STATE REGULATOR]. All blowout prevention equipment, including diverter systems, shall be installed, operated, tested and maintained in accordance with API RP 53 (Recommended Practices for Blowout Prevention Equipment Systems) and API RP 64 (Diverter Systems Equipment and Operations) and conform to BOP requirements of [STATE REGULATOR]. The required working pressure rating of all blowout preventers and related equipment shall be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practices, and shall exceed the maximum anticipated pressure to be contained at the surface. Ram-type preventers shall have a working pressure at least 10% greater than the maximum anticipated pressure. In the absence of better data, the maximum anticipated surface pressure shall be determined by using a normal pressure gradient of 0.433 psi per foot and assuming that one-third (1/3) of the drilling mud is evacuated from the wellbore when at the interval's shallowest true vertical depth. A drill pipe safety valve shall be installed or at the ready to prevent backflow of fluids into the drill string. A choke line of sufficient size and working pressure shall be installed. During drilling operations, the ram-type blowout preventers shall be tested by closing at least once each trip and the annular-type preventer shall be tested by closing on the drill pipe at least once each week. Well control drills shall be performed at least every (7) days for each drilling crew, if operations permit.

(d) If, during drilling operations, the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid resulting in any of the following circumstances: (a) influx of formation fluids into the wellbore resulting in a pit gain; (b) increase in fluid return rate; or (c) change in drilling parameters that requires well control procedures to increase hydrostatic pressure and to circulate out the influx of formation fluids, the operator shall report the incident to [STATE REGULATOR]. The well control operation report shall include the following information recorded during the operation: depth of kick, duration of kick, shut-in drill pipe and annular pressures, pit gain volume, mud density, and circulating pressures and volumes required to reach desired mud density.

(e) If drilling with a mud system, the drilling fluid system must be designed to maintain control of the well and with rheological properties to minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics for purposes of being able to maintain well control shall be maintained at the well location. A drilling fluid monitoring unit must be used and continuously observed during drilling operations, including tripping, to monitor and record: gas entrained in the drilling fluid; drilling fluid density; drilling fluid salinity; the rate of penetration; and hydrogen sulfide. The rig must be equipped with a recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator must include both a visual and an audible warning device. Mud quality tests shall be made at least once per day, including: density, viscosity, and gel strength; hydrogen ion concentration (pH); filtration and other tests the [STATE REGULATOR] may require. The wellbore shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to keep the wellbore full shall be measured to assure that it corresponds with the displacement of pipe pulled. A careful watch for swabbing action shall be maintained when pulling out of the hole.

(f) To allow for air drilling or managed pressure drilling (MPD), all wells being drilled to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped with a rotating control head (for low pressure air drilling) or rotating BOP (for MPD) to divert any wellbore fluids and gases away from the rig floor to a flare pit a safe distance from the well while drilling. A diverter system may be installed in the BOP section if risk of shallow gas is anticipated. All diverter systems shall be maintained in effective working condition and shall be function tested when installed and at regular intervals during drilling operations in accordance to API RP 64 (Diverter Systems Equipment and Operations). There shall be two diverter control stations, one on the drilling floor and one located at a safe distance and readily accessible away from the drilling floor. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(g) An accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components must be installed, with an automatic backup. The system must perform with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging. Minimum requirements for accumulator testing shall include precharge of accumulator bottle, accumulator response time and the capability of closing on the minimum size drill pipe being used.

(h) All hole intervals drilled prior to reaching the base of protected water must be drilled with air, fresh water or a fresh water-based drilling fluid. Freshwater drilling mud additives, if used, must be non-hazardous. Drilling with synthetic muds and oil-based muds is prohibited in intervals above the base of protected water. The [STATE REGULATOR] may specify drilling fluid requirements or additives for any hole intervals and may exclude particular drilling fluid constituents based on regional knowledge of protected water conditions.

(i) Operator must notify [STATE REGULATOR] at least 24 hours prior to commencing any BOP testing, casing integrity testing, casing cementing operations, and regulated cement evaluation pursuant to this Article III.

(j) Upon completion of each well, a casing and cementing report and an as-built well construction drawing shall be filed with [STATE REGULATOR] furnishing complete data concerning the casing string(s) set and the cementing of all casing in the well including top of cement for each casing string, as specified on a form furnished by [STATE REGULATOR]. The operator or its duly authorized agent having personal knowledge of the facts, and representatives of the drilling and cementing company, shall sign the form attesting to compliance with the well construction requirements of [STATE REGULATOR].

(k) The drilling, casing and completion program for the well shall be designed to prevent pollution. All protected water zones must be isolated and sealed off to effectively prevent contamination or harm. All corrosive zones and all hydrocarbon strata that are capable of annular flow that could negatively impact the quality of the cement and/or casing or result in annular overpressurization must be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing.

(l) In areas where a sufficient number of wells have been drilled, and the protection depth is well established by core samples, resistivity logs, and/or hydrological assessments, and has been mapped and approved by [STATE REGULATOR], [STATE REGULATOR] may approve the location-specific surface casing depth for the well based upon its approved maps. In undeveloped areas where the protection depths are not well documented, a conservative surface casing depth will be estimated by [STATE REGULATOR], and the operator shall be required to collect site-specific data to verify the protection depth, and obtain [STATE REGULATOR] approval for that depth prior to setting and cementing surface casing and intermediate casing.

(m) An operator shall perform an anti-collision evaluation of all active (producing, shut in, or temporarily abandoned) offset wellbores that have the potential of being within 150 feet of a proposed well prior to drilling operations for the proposed well. Notice shall be given to all such offset operators prior to drilling.

(n) Proper casing running practices such as controlling running speed and circulation rates while monitoring fluid returns, torque, and hook load readings, shall be used in order to manage equivalent circulating density (ECD) and torque and drag when casing is being installed. For makeup of API connections, operator shall follow API 5B (Specifications for Threading, Gauging, and Thread Inspection of Casing, Tubing and Line Pipe Threads). The manufacturer's makeup/handling procedures shall be used for proprietary connections.

(o) Cementing shall be by the pump and plug method. A cement sheath of at least 0.75 inches shall fill the space between the outside diameter of the casing tube and the drilled diameter of the borehole (i.e. the annular gap). At least 25% excess cement shall be used, unless a four-arm caliper log, a fluid caliper or an equivalent analytical method is used to more accurately assess hole shape and the required cement volume. Cement must fill the annular space outside each string of casing as more particularly described in Sections 3.4(d) (surface casing), 3.5(d) (intermediate casing) and 3.6(a) (production casing).

(p) The hole shall be prepared before cementing to ensure an adequate cement bond between the casing and the formation by (i) circulating and conditioning the drilling fluid with a minimum of two hole volumes, (ii) adjusting drilling fluid rheology, density, and operations to optimize conditions for displacement of the drilling fluid and (iii) ensuring that the wellbore is static and that all fluid and gas flows are killed. Spacer fluids shall be used to separate mud and cement and to avoid mud contamination of the cement. Circulation must be established prior to commencement of cementing, if technically feasible. If circulation cannot be established, operator shall ensure effective isolation of zones requiring isolation, as described in Section 3.4 (surface casing), 3.5 (intermediate casing) and 3.6 (production casing).

(q) Cement shall be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus. During placement of the cement, operator shall monitor pump rates to verify that they are within design parameters to ensure proper displacement efficiency. Throughout the cementing process operator shall monitor cement mixing in accordance with

cement design and cement densities during the mixing and pumping. Casing shall be rotated and/or reciprocated during cementing to improve cement placement, if feasible.

(r) Cement shall conform to API Specification 10A (Specification for Cement and Material for Well Cementing). [STATE REGULATOR] may require specific cement additives, quantities, or types in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area surrounding the well. Consideration shall be given to including gas blockers or static gel strength accelerators if permeable gas-bearing intervals are being cemented, and to including designs addressing downhole conditions such as CO₂ and H₂S degradation if conditions dictate. Operator may request use of other cement types for approval by [STATE REGULATOR] by providing detailed cement design and test criteria as described in API RP 65-2 (Isolating Potential Flow Zones During Well Construction).

(s) Casing strings shall stand under pressure until the cement has reached a compressive strength of at least 500 psi (to be achieved within 24 hours at most) in the zone of critical cement before drilling out the plug, initiating a test, or disturbing the cement in any way. Casing hardware (e.g. float valves and toe valves) shall be used and verified to have held to prevent cement backflow in the casing string. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(t) Before drilling the cement plug, operator shall test the casing to a surface pressure, in pounds per square inch (psi), of at least the maximum anticipated pressure to be contained at the surface by the casing string, as calculated by the method in Section 3.2(c) above; provided, however, the maximum test pressure shall not exceed 80% of API rated minimum internal yield of the casing. A successful test is one where the pressure stabilizes within 10% of the required test pressure and remains stable for a full 30 minute test period. A failed test requires notification to [STATE REGULATOR] and immediate well work to remedy the failure, and a repeat test until successful.

(u) Cement slurry shall be prepared to optimum density and to minimize, to the greatest extent practicable, its free fluid content. In no event shall the free fluid separation for the slurry average more than (i) two milliliters per 250 milliliters of cement tested for cement inside the zone of critical cement or (ii) three and one-half milliliters per 250 milliliters of cement tested for cement outside the zone of critical cement. Cement mix water chemistry must be proper for the cement slurry designs. An operator's representative shall be on site verifying that the cement mixing, testing, and quality control procedures used for the entire duration of the cement mixing and placement are consistent with the approved engineered design, relevant API standards, and the requirements of this Article.

(v) Cement mixtures shall be tested when there is a change in operating conditions, cement type, cement vendor, or every six months, whichever is more frequent, by the operator or the company providing the cementing services. Tests shall be made on representative samples of cement and additives using the equipment and procedures required by API RP 10B-2 (Recommended Practice for Testing Well Cements). Cement design and test data must be furnished to [STATE REGULATOR] prior to the cementing operation. To determine that the

minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators, used in the slurry) at the following temperatures and at atmospheric pressure:

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement; and

(ii) For lead cement (the first cement pumped in the job), the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the midpoint of the lead cement.

(w) Operator shall provide adequate centralization and/or other methods to aid in proper cementation to meet well design objectives. All centralizers shall meet API Spec 10D (Specification for Bow-Spring Casing Centralizers) or API 10TR (Technical Report on Consideration Regarding Selection of Centralizers for Primary Cementing Operations) and 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). Casing-specific guidelines for centralization are found in sections 3.4(e) (surface casing), 3.5(e) (intermediate casing), and 3.6(a) (production casing).

(x) During drilling, casing and cementing operations, operators shall report defective casing or cementing within 24 hours of discovery and shall immediately correct the defect, unless [STATE REGULATOR] determines that the defect does not warrant immediate repairs to protect human health, safety and the environment and can safely be completed within a time period approved by [STATE REGULATOR]. If the defect cannot be corrected within 30 days or within another time period approved by [STATE REGULATOR], the well shall be plugged and abandoned.

(y) Each operator shall have a functioning emergency response plan, available on site, that includes training, drills, and appropriate certifications, and provides for the efficient management of emergency situations arising from operations covered hereunder.

3.3 **Conductor Casing.**

(a) Conductor casing shall be set to stabilize unconsolidated sediments and isolate shallow groundwater.

(b) Conductor casing shall be set to a depth sufficient to provide solid structural anchorage for a diverter system in air drilling operations, unless the operator provides sufficient technical justification to [STATE REGULATOR] that the absence of conductor casing will not jeopardize well control. Conductor casing shall be new casing and be placed across the entire length of the conductor casing hole.

(c) Conductor casing may be driven into the ground, or a hole may be drilled into the ground and the conductor casing set and cemented in that hole. Where the conductor casing is used to isolate protected water, it shall be fully cemented as per 3.3(d).

(d) Conductor casing set in a drilled hole must be cemented by filling the annular space with cement from the shoe to the surface. Operator must verify cement is returned to the surface and that the annular space is completely filled with cement.

(e) Conductor casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, groundwater and potential drilling hazards.

(f) A mechanical or cement seal must be installed at the surface to block downward migration of surface pollutants.

3.4 **Surface Casing.**

(a) Surface casing shall be installed to isolate protected water, provide the structure to support blowout prevention equipment, provide a conduit for drilling fluids while drilling the next section of the well, and contain pressures and fluids from subsequent drilling, completion, and production operations. Surface casing shall not be used as the production casing in the well in which it is installed, and may not be perforated for purposes of conducting a hydraulic fracturing treatment through it.

(b) Operator shall set and cement sufficient surface casing to a minimum depth of at least 50 feet below the base of the deepest strata containing protected water, but above any hydrocarbon strata that are capable of annular flow that could negatively impact the quality of the cement or result in annular overpressurization. If it is not possible to set and cement surface casing above such hydrocarbon strata, the water shall be protected with intermediate casing pursuant to section 3.5(b). Surface casing shall be set deep enough and into a competent formation to ensure the BOP can contain any formation pressure that may be encountered when drilling the next section of the hole below the surface casing shoe. In no case, however, is surface casing to be set deeper than 200 feet below the base of the deepest strata containing protected water without prior approval from [STATE REGULATOR].

(c) If a shallow gas hazard is encountered, surface hole drilling shall stop after drilling through that interval, and surface casing shall be set and cemented before drilling deeper. All well designs shall account for shallow gas hazards. Any shallow gas hazards encountered while drilling shall be recorded and reported to [STATE REGULATOR] as part of the post-treatment report and made available to other operators in the area.

(d) Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, or other operations (e.g. cement fallback) indicate inadequate cement coverage, the operator or the operator's representative shall submit a plan of remediation to [STATE REGULATOR] for approval and implement such plan by performing additional operations to remedy such inadequate coverage prior to continuing drilling operations.

(e) A centralizer shall be placed every fourth joint from the cement shoe to within 120 feet of the ground surface, or casing shall be centralized by implementing an alternative centralization plan approved by [STATE REGULATOR]. At a minimum, casing shall be centralized within 120 feet of the top, at the shoe, above and below a stage collar or diverting tool, if run, and through all protected water zones.

(f) Prior to drilling out below the surface casing shoe, the surface casing shall be pressure tested at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

(g) Mechanical integrity test of surface casing after drillout.

(i) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent [STATE REGULATOR]-approved casing evaluation method, unless otherwise approved by [STATE REGULATOR].

(ii) If a mechanical integrity test is conducted, the [STATE REGULATOR] shall be notified at least eight hours before the test is conducted to give [STATE REGULATOR] an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by [STATE REGULATOR], and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. [STATE REGULATOR] shall be notified within 24 hours after a failed test. Operations may not recommence until [STATE REGULATOR] approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.

(h) A formation integrity test (FIT) shall be completed after drilling out below the surface casing shoe, into at least 20 feet, but not more than 50 feet, of new formation if the fracture gradient of the formation is unknown, or if [STATE REGULATOR] determines such a test is otherwise necessary to: demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill; no flow path exists to formations above the casing shoe; and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. In the event the FIT fails to meet these criteria, the operator shall submit a remediation plan to [STATE REGULATOR] for approval and implement such plan prior to continuing operations.

3.5 **Intermediate Casing.**

(a) Intermediate casing shall be installed when necessary to isolate protected water not isolated by surface casing and to seal off anomalous or higher pressure zones, corrosive zones, zones capable of causing annular flow that could negatively impact the quality of the cement and/or

casing or result in annular overpressurization, lost circulation zones and other drilling hazards. Without an exemption, intermediate casing used to isolate protected water shall not be used as the production string in the well in which it was installed, nor be perforated for purposes of conducting a hydraulic fracturing treatment through it.

(b) Intermediate casing shall be set to protect groundwater if surface casing was set above the base of protected water, and/or if additional protected water was found below the surface casing shoe. When intermediate casing is installed to protect groundwater, the operator shall set a full string of new intermediate casing to a minimum depth of at least 50 feet below the base of the deepest strata containing protected water and cement to the surface. The location and depths of any hydrocarbon strata or protected water strata open to the wellbore above the casing shoe prior to cementing shall be confirmed by MWD (measurement while drilling), LWD (logging while drilling), coring, electric logs, or testing and shall be reported as part of the post-treatment report.

(c) Abnormal pressure zones, lost circulation zones, and other drilling hazards encountered while drilling below the surface casing shall be recorded and reported to [STATE REGULATOR] and made available to other operators in the area as part of the post-treatment report.

(d) In the case that intermediate casing was set to isolate zones identified in section 3.2(k), the casing shall be cemented from the shoe up to a point at least 600 true vertical feet above the top of the shallowest such zone. If the intermediate casing was set for another reason (e.g. pressure management), the casing shall be cemented from the shoe to a point at least 600 true vertical feet above the shoe. In either case, cement need not be brought up further than 200 feet into the next shallower casing string that was set and cemented in the well. Liners may be set and cemented per requirements for intermediate casing provided that the cemented liner has a minimum of 200 feet of cemented lap within the next larger intermediate casing, and the liner top is pressure tested to a level equal to or higher than the maximum anticipated pressure to be encountered in the interval to be drilled below the liner. The location and depths of productive horizons, or any hydrocarbon strata that is open to the wellbore above the casing shoe shall be confirmed prior to cementing by MWD/LWD, coring, electric logs or testing.

(e) The intermediate casing string or intermediate liner shall be centralized in order to provide adequate casing standoff for mud removal and cement placement.

(f) Prior to drilling out below the intermediate casing shoe, the intermediate casing shall be pressure tested at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

(g) A formation integrity test (FIT) shall be completed after drilling out below the intermediate casing shoe, into at least 20 feet, but not more than 50 feet, of new formation if the fracture gradient of the formation is unknown, or if [STATE REGULATOR] determines such a test is otherwise necessary to demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill; no flow path exists to formations above the casing shoe; and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. In the event the FIT fails to meet

these criteria, the operator shall submit a corrective action plan to [STATE REGULATOR] for approval and implement such plan in order for the operator to proceed with its operations.

(h) In the event the distance from the casing shoe to the top of the shallowest productive horizon, corrosive zones, hydrocarbon strata that are capable of annular flow that could negatively impact the quality of the cement and/or casing or result in annular overpressurization, other drilling hazards, or strata containing protected water, makes cementing as specified above impossible or impractical, multi-stage cementing operations may be used to cement the casing in a manner that will effectively seal off all such horizons or strata and prevent fluid migration to or from such horizons or strata within the wellbore.

(i) If operations (e.g. fluid returns, lift pressure, displacement) indicate inadequate coverage of any productive horizon, corrosive zones, hydrocarbon strata that are capable of annular flow that could negatively impact the quality of cement and/or casing or result in annular overpressurization, or any strata containing protected water, the operator or the operator's representative shall submit a plan to determine top of cement and for remediation to [STATE REGULATOR] for approval and implement such plan by performing additional operations to remedy such inadequate coverage prior to continuing drilling operations.

(j) When a hydraulic fracturing treatment is conducted through intermediate casing, operator shall run a radial cement evaluation tool to assess cement integrity and placement, in addition to evaluating cementing records and the results of annular pressure monitoring. If the cement evaluation tool indicates insufficient isolation, operator shall inform [STATE REGULATOR] and comply with [STATE REGULATOR'S] site-specific guidance for remedying cementing deficiencies prior to drilling further into the hole. If such deficiencies cannot be remedied, the well must be plugged and abandoned.

(k) Operator may request an exemption from the requirement in 3.5(j) to run a cement evaluation tool for a specified number of wells or period of time if operator has:

(i) successfully set and cemented the casing for which the exemption is requested in at least 5 wells drilled by the same operator in a portion of the operating field characterized by similar conditions.

(ii) has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones, or lost circulation zones;

(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; and

(iv) submitted an exemption request to [STATE REGULATOR] containing the information required under (i) – (iii) above.

3.6 **Production Casing.**

(a) Production casing shall be cemented by the pump and plug method, or another method approved by [STATE REGULATOR], with sufficient cement to fill the annular space to a measured depth at least 600 feet above (i) the production casing shoe or the uppermost perforation in a vertical well (whichever is higher), or (ii) the point where a horizontal well first penetrates the zone to be hydraulically fractured. If any zones referenced in 3.2(k) are open to the wellbore above the production casing shoe, the production casing shall be cemented in a manner that effectively seals off all such horizons or strata by one of the methods specified for intermediate casing in Section 3.5(d) above.

A full string of production casing shall be installed and cemented if both surface casing and intermediate casing are used as water protection casing. A production liner may be hung from the base of the intermediate casing and used as production casing as long as the surface casing is used as the water protecting casing and intermediate casing is set for a reason other than isolation of protected water. The production liner must be cemented with a minimum measured depth of 200 feet of cemented lap within the next larger casing. The liner top must be pressure tested to a level that is at least 500 psi higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The production casing string or production liner must be centralized in a manner that will enable proper zonal isolation by the cement. Casing centralizers should be used in vertical and build sections of those wells where the cement is being considered as a barrier to the growth of hydraulic fractures. Casing should be centralized in order to provide adequate casing standoff for mud removal and cement placement.

(b) The identification of the productive horizon(s) shall be determined by MWD/LWD, coring, electric log, mud-logging, or testing. For cemented well completions, the production casing shall be landed and cemented into or below the productive horizon(s). For open-hole well completions, the production casing shall be landed and cemented into or above the productive horizon(s).

(c) Abnormal pressure zones, lost circulation zones, and other drilling hazards encountered while drilling the production hole section must be recorded and reported to [STATE REGULATOR] and made available to other operators in the area as part of the post-treatment report.

(d) In addition to an evaluation of cementing records and annular pressure monitoring results, operator shall run a radial cement evaluation tool to further assess cement integrity and placement. If cement evaluation indicates insufficient isolation, operator shall submit a plan of remediation to [STATE REGULATOR] for approval and implement such plan by performing remedial operations prior to commencing completion operations. If the deficiencies cannot be remedied, the well shall be plugged and abandoned.

(e) Operator may request an exemption from the requirement above in 3.6(d) to run a cement evaluation tool for a specified number of wells or period of time if the operator has:

(i) successfully set and cemented the casing for which the exemption is requested in at least 5 wells drilled by the same operator in a portion of the operating field characterized by similar conditions;

(ii) has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;

(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; and

(iv) submitted an exemption request to [STATE REGULATOR] containing the information required under (i) – (iii) above.

(f) Open hole, open hole packer, or other non-cemented completions may be used in the place of cemented completions. If intermediate casing is run with this type of completion, the cementing of the intermediate casing must meet the cementing guidelines set forth in Section 3.5 hereof. If intermediate casing is not run, a multi-stage cementing tool must be run above the top external packer and cemented to fill the annular space outside the casing to the surface or to a point at least 600 feet above the packer or casing shoe.

3.7 **Minimum Separation Wells.**

(a) Minimum separation wells may not utilize open hole, open hole packer, or other non-cemented completions.

(b) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).

(c) The production casing for minimum separation wells shall not be disturbed for a minimum of 8 hours after cement is in place unless approved by [STATE REGULATOR], and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.

(d) In addition to an evaluation of cementing records and annular pressure monitoring results, operator shall run a radial cement evaluation tool to further assess cement integrity and placement. If cement evaluation indicates insufficient isolation, operator shall submit a plan of remediation to [STATE REGULATOR] for approval and implement such plan by performing remedial operations prior to commencing completion operations. If the deficiencies cannot be remedied, the well shall be plugged and abandoned.

(e) Operator may request an exemption from the requirement above in 3.7(d) to run a cement evaluation tool for a specified number of wells or period of time if the operator has:

(i) successfully set and cemented the casing for which the exemption is requested in at least 5 minimum separation wells drilled by the same operator in a portion of the operating field characterized by similar conditions;

(ii) has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;

(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; and

(iv) submitted an exemption request to [STATE REGULATOR] containing the information required under (i) – (iii) above.

3.8 **Approved Cementers.**

(a) In order to comply with the provisions of this Article, when conducting well construction operations which require cementing, operators shall utilize only those cementers approved by [STATE REGULATOR]. Companies may apply with [STATE REGULATOR] for designation as approved cementers.

(b) A cementing company, service company, or operator seeking designation as an approved cementer by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform cementing operations in compliance with this rule.

(c) [STATE REGULATOR] shall either approve or deny the application to be designated as an approved cementer. If [STATE REGULATOR] does not recommend approval or denies the application, the applicant may request a hearing on its application.

3.9 **Inclination and Directional Surveys.**

(a) Nothing in this Section 3.9 shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease, unit boundary and/or property lines without special permission from [STATE REGULATOR].

(b) Certain inclination survey requirements are as follows:

(i) An inclination survey made by a surveying company approved by [STATE REGULATOR] shall be filed on a form prescribed by [STATE REGULATOR] for each well drilled or deepened, except as hereinafter provided; or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

(ii) Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

(iii) Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed, as a part of or in addition to the inclination surveys otherwise required. If computations are made from dipmeter surveys to determine the course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

(iv) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease or unit line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

(v) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

(vi) Inclination surveys will not be required on wells that are drilled as dry holes and are permanently plugged and abandoned. If such wells are reentered at a later date and completed as producer, injection, or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

(vii) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with [STATE REGULATOR]. If such data are not on file with [STATE REGULATOR], the results of an inclination survey must be reported on the appropriate form and filed pursuant to the applicable rules of [STATE REGULATOR], except as otherwise provided in this Section 3.9.

(c) Certain survey report requirements are as follows:

(i) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each

two successive shot points (assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point), and the total possible accumulative drift (assuming that all measured angles of inclination are in the same direction).

(ii) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at the operator's direction on the operator's behalf, either:

(1) that the well was not intentionally deviated from vertical; or

(2) that the well was deviated at random, with an explanation of the circumstances.

(iii) The report shall be filed with [STATE REGULATOR] by attaching one copy to each appropriate completion form for the well. [STATE REGULATOR] may require the submittal of the original charts, graphs, or discs resulting from the surveys.

(d) Certain requirements governing directional surveys are as follows:

(i) 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 unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at the operator's own expense by an approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits.

(ii) Directional surveys shall be required on each well drilled under the directional deviation provisions of this Section 3.9.

(iii) No hydrocarbon allowable shall be assigned to any well on which a directional survey is required until a directional survey has been filed with and accepted by [STATE REGULATOR].

(iv) Directional surveys shall be required for each horizontal wellbore, from the surface to the farthest point drilled in the applicable horizontal wellbore.

(e) Directional surveys required under this Section 3.9 must be run by competent surveying companies, approved by [STATE REGULATOR], signed and certified by a person having actual knowledge of the facts, in the manner prescribed by [STATE REGULATOR].

(f) All directional surveys, unless otherwise specified by [STATE REGULATOR], 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 or unit lines.

(g) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth; if well is included in an anti-collision analysis as per 3.2(m), additional surveys may be required. 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.

(h) Intentional deviation of wells.

(i) A permit for directionally deviating a well may be granted:

(1) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

(2) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

(3) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

(4) 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;

(5) for the purpose of drilling a horizontal wellbore; or

(6) for other reasons found by [STATE REGULATOR] to be sufficient after notice and hearing.

(ii) Permission for the random deviation of a well may be granted whenever the necessity for such deviation is shown, as prescribed in this Section 3.9.

(iii) Applications for deviation.

(1) Applications for wells to be directionally deviated must specify on the application to drill the surface location of the well and the projected bottom hole location of the well. For intentionally deviated "horizontal" wells, the plat shall also include the kick-off and landing points. On the plat, in addition to the plat requirements provided for in the applicable permitting rules, the following shall be included:

(A) two perpendicular lines providing the distance in feet from the projected bottom hole 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;

(B) a line providing the distance in feet from the projected bottom hole 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;

(C) a line providing the distance in feet from the projected bottom hole 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

(D) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottom hole location.

(2) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice of such necessity to [STATE REGULATOR], and upon giving such notice, the operator may proceed with the directional deviation. An operator proceeding with the drilling of a deviated well under such circumstances does so at the operator's 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 [STATE REGULATOR] under the applicable rules governing such permits. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

(3) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice of such necessity to [STATE REGULATOR], and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this Section 3.9 on inclination surveys.

(i) [STATE REGULATOR], at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of approved survey, shall be made with regard to a well for which a complaint is filed in the same field.

(i) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease or unit boundary lines.

(ii) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by [STATE REGULATOR] as security against all costs and risks associated with the survey.

(iii) The complaining party and [STATE REGULATOR] shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company approved by [STATE REGULATOR].

(iv) The survey shall be witnessed by [STATE REGULATOR], and may be witnessed by any party, or that party's agent, who has an interest in the field.

(v) Nothing in these rules shall be construed to prevent or limit [STATE REGULATOR], acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with applicable rules and regulations.

(j) Directional Survey Report - For each well drilled for hydrocarbons for which a directional survey report is required by rule, regulation, or order, the surveying company shall prepare and file the following information in machine-readable electronic format. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(i) the name of the surveying company;

(ii) the name of the individual performing the survey for the surveying company;

(iii) the title or position the individual holds with the surveying company;

(iv) the date on which the individual performed the survey;

(v) the type of survey conducted and whether the survey was multishot;

(vi) complete identification of the well, including any applicable identifying information required by [STATE REGULATOR];

(vii) a notation that the survey was conducted from a depth of ____ feet to ____ feet; and

(viii) For each well drilled, a 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 or unit boundary lines, shall be mailed by registered, certified, or overnight mail direct to [STATE REGULATOR] by the surveying company making the survey.

ARTICLE IV

WELL OPERATIONS – COMPLETION, HYDRAULIC FRACTURING AND SUBSEQUENT WELL OPERATIONS

4.1 **Scope of Article.** It is the intent of all provisions of this Article that, in respect to completion, hydraulic fracturing treatment, recompletion, reentry, or refracturing operations: (i) the well shall be stimulated in such a manner that all injected hydraulic fracturing fluids be directed into the zone(s) to be hydraulically fractured and that protected water zones are not contaminated by hydraulic fracturing fluids, proppants, hydrocarbons or other mobilized contaminants; (ii) an evaluation of the intervening zone be completed to verify that impermeable confining layers exist that will prevent contamination of protected water; (iii) other wellbores and known transmissive faults and fractures in the area be identified and evaluated as potential conduits and addressed per 2.3(a)(xiv); (iv) the wellbore's mechanical integrity shall be positively assessed, tested and maintained throughout the hydraulic fracturing operation and the remaining life of the well; (v) all additives contained in the hydraulic fracturing fluid shall be of known quantity and description; (vi) hydraulic fracturing treatments shall be designed using good engineering practices; (vii) operator shall conduct and monitor operations in accordance with all the requirements of this Article IV; (viii) perforations and hydraulic fracturing treatments shall not be made through surface casing or any intermediate casing used to isolate protected water; (ix) operator shall maintain at least two independent barriers, including one mechanical barrier, across each flow path during completion activities; and (x) procedures are in place for health professionals to have timely access to the chemical composition of all additives used in hydraulic fracturing fluids, including any chemicals that are entitled to trade secret protection under applicable law. [STATE REGULATOR] shall administer this Article consistent with this intent. When this Article does not detail specific methods to achieve these objectives, operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

4.2 **General Well Control requirements.**

(a) All completion and workover wells shall have blowout preventer equipment installed and tested as soon as practical for each completion stage to keep the well under control at all times, in conformance with BOP requirements of [STATE REGULATOR].

(b) The working pressure of the blowout preventer (excluding the annular preventer) shall be at least 10% greater than the maximum anticipated pressure during the completion or workover operations.

(c) Cased hole operations with a workover rig shall require blowout preventer equipment as specified in Section 4.2(a) and (b) as follows:

(i) Manually operated blowout preventer stacks shall be installed and fully functional for workover operations below 5,000 psi. Remote operations shall be required for operations at greater pressures or for H₂S service.

(ii) Choke and kill lines shall be designed for the appropriate operating pressure, installed and tested as rated, and secured properly.

(iii) A tubing string safety valve shall be available at all times on the rig floor if needed for well control operations.

(iv) Tripping practices to maintain well control shall be followed at all times while tripping in and out of the hole.

(d) Cased hole operations with a coiled tubing unit shall require that a coiled tubing blow out preventer and stripper assembly be installed and tested with a working pressure as specified in Section 4.2(b).

(i) An annular pressure gauge shall be installed and tested to monitor annular pressure between coiled tubing and outer tubing/casing string.

(e) Cased hole operations with a snubbing or rig assist unit designed to work on a well under pressure shall require equipment and tubing string design for anticipated well forces (burst, collapse, tension and buckling), and sizes for clearances of all equipment during all aspects of the operations. All associated BOP equipment shall be rated and tested as specified in Sections 4.2(a) and (b).

(i) Prior to beginning operations, the tubing workstring shall be visually inspected and pressure tested to at least 20% greater than the anticipated maximum pressure during operations.

4.3 **Before Hydraulic Fracturing Treatment.**

(a) Prior to commencing completion or refracturing operations, or commencing hydraulic fracturing operations on a well that has not previously undergone a hydraulic fracturing treatment, all cemented casing strings and all tubing strings to be used by an operator in conducting the hydraulic fracturing treatment shall be tested to a pressure at least 500 psi greater than the anticipated maximum surface pressure to be experienced during the completion operations. A successful pressure test is one where the pressure stabilizes within 10% of the required test pressure and remains stable for a full 30 minute test period. A failed test requires notification to [STATE REGULATOR] and immediate wellwork to remedy the failure, and a repeat test until successful. Non-cemented production completions shall be tested to a minimum of (i) 70% of the lowest activating pressure for pressure actuated sleeve completions or (ii) 70% of formation integrity for open-hole completions, as determined by a formation integrity test.

(b) Prior to beginning operations, all casing strings that will be exposed to hydraulic fracture treatment pressures shall have cement evaluation performed as described in Article III. If hydraulic fracturing will be completed on an existing well and cement evaluation has not previously been performed, such work must be successfully completed prior to performing the hydraulic fracturing treatment. If the cementation is insufficient, then operator must develop and successfully execute plan of remediation approved by [STATE REGULATOR] before proceeding.

(c) Prior to beginning a hydraulic fracturing treatment, any surface equipment to be utilized by operator in such hydraulic fracturing treatment shall be rigged up and pressure tested for the proposed treatment design. At a minimum, all surface equipment shall be tested to 110% of the maximum anticipated surface treating pressure to ensure appropriate safety factor and to prevent fluid losses.

(d) At least 24 hours prior to commencing a hydraulic fracturing treatment, operator shall notify [STATE REGULATOR] that operator is going to begin such hydraulic fracturing treatment.

(e) The operator conducting any well stimulation shall give prior written notice, up to seven days and not less than three business days, to any operator of a well completed in or penetrating the same formation, if publicly available information indicates or if the operator is made aware if the completion intervals or penetrations are within one mile, or such other distance provided by [STATE REGULATOR], of one another.

(f) Prior to beginning a hydraulic fracturing treatment on a minimum separation well, operator shall submit a hydraulic fracturing design plan for [STATE REGULATOR's] approval. This plan must:

(i) Verify that the well proposed to be hydraulically fractured meets the well construction standards of Article III;

(ii) Include an analysis of the site-specific hydrology and geophysical characteristics of the intervening zone and confining layer(s) contained within the intervening zone. The purpose of the analysis is to demonstrate that the confining layer(s) has sufficient areal extent, impermeability, and absence of transmissive faults or fractures such that the proposed hydraulic fracturing treatment design will not: (a) result in the vertical migration of the fracturing fluids, hydrocarbons, or other contaminants into strata that contains protected water; or (b) result in a horizontal fracture that intersects with a nearby well that could result in the vertical migration of the fracturing fluids, hydrocarbons, or other contaminants into strata that contains protected water. A confining layer is of sufficient areal extent and thickness if it is capable of preventing or arresting vertical fracture propagation;

(iii) The confining layer analysis shall include information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and intervening zone in the area of investigation, including (a) geologic name and description of all formations penetrated, including relevant logs, (b) structure maps, including any faults, and (c) any geomechanical analyses, including permeability, relative hardness (using Young's Modulus) and relative elasticity (using Poisson's Ratio). The confining layer analysis may be submitted on a well-by-well basis, or may be approved by [STATE REGULATOR] for an area and referenced as a pre-approved confining layer analysis in the well application for minimum separation wells drilled in such area;

(iv) Utilize and submit an appropriate 3D fracture design model populated with the most current data available that allows for multiple stage and multi-zone modeling to show that the hydraulic fracturing treatment will not propagate fractures into strata containing protected water utilizing appropriate reservoir and geologic properties over the entire length of the wellbore; and

(v) Describe in detail the proposed hydraulic fracturing treatment design, including the volumes, pressures, pump rates, hydraulic fracture fluid type, proppants and additives proposed.

(g) Prior to beginning a hydraulic fracturing treatment on a minimum separation well, the operator shall run a radial cement evaluation log or such other cement evaluation tool capable of identifying a cement channel as may be approved by [STATE REGULATOR] to determine the quality of the cement outside of the production casing. If the quality of the cement outside of the production casing is not sufficient to isolate strata containing protected water, then the operator must develop a plan of remediation and receive approval from [STATE REGULATOR] prior to proceeding.

4.4 **During Hydraulic Fracturing Treatment.**

(a) Operator shall monitor all wellbore annuli during the hydraulic fracturing treatment pursuant to 4.4(b) and, shall report (i) surface casing pressure or volume changes described in 4.4(b), (c), (d),; or (ii) a pressure that exceeds 80% of API rated minimum internal yield on any casing string in communication with the hydraulic fracturing treatment.

(b) Operator must continuously monitor and record the following parameters during any hydraulic fracturing treatment:

- (i) surface injection pressure (psi);
- (ii) slurry rate (bpm);
- (iii) proppant concentration (ppa);
- (iv) fluid rate (bpm);
- (v) identities, rates, and concentrations of additives used; and
- (vi) all annuli pressures and/or volumes expressed at surface.

With regard to the monitoring of the surface casing annulus and the intermediate by production casing annulus, the annular pressure shall be monitored with a gauge and pressure relief device. The maximum set pressure on the relief device shall be the lower of (i) a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet) or (ii) 70% of the API rated minimum internal yield for the surface casing. If the annular pressure exceeds the maximum set pressure or there is an annular pressure change a pressure change that is 20% or

greater than the calculated pressure increase due to pressure and/or temperature expansion, the hydraulic fracturing treatment shall be immediately terminated and [STATE REGULATOR] shall be notified within 24 hours of the occurrence if any of these excessive pressures are observed in the surface casing annulus. Pressures on any casing string other than the surface casing should not be allowed to exceed 80% of the API rated minimum internal yield pressure for such casing string throughout the hydraulic fracturing treatment.

(c) If the hydraulic fracturing treatment design does not allow the surface casing annulus to be shut-in and monitored with a gauge, then the surface casing annulus shall be open to atmospheric pressure and continuously monitored for flow and recorded throughout the hydraulic fracturing treatment. The hydraulic fracturing treatment shall be terminated if a volume of fluid expressed at surface that is in excess of a volume that could reasonably be expected due to thermal expansion, and [STATE REGULATOR] shall be notified and corrective actions taken

(d) If during a hydraulic fracturing treatment, operator has reason to suspect any potential failure of the production casing, the production casing cement, or the isolation of any sources of protected water due to excessive fracture height growth or the intersection of the hydraulically induced fracture with a transmissive fault or offset wellbore that causes an increase in annular pressure in such offset wellbore, then operator must immediately discontinue the hydraulic fracturing treatment, notify [STATE REGULATOR] within 24 hours of the occurrence of any such event and perform diagnostic testing on the well as is necessary to determine (i) whether such a failure has actually occurred, and (ii) the presence or absence of migration pathways into any strata containing protected water. The diagnostic testing shall be done as soon as is reasonably practical after operator has reasonable cause to suspect any such failure, and if the testing reveals that a failure has occurred, then operator shall shut-in the well and isolate the perforated interval as soon as is reasonably practical and notify [STATE REGULATOR] of same. Prior to conducting any further operations on the well, wellbore integrity must be restored and demonstrated to [STATE REGULATOR] and operator must show that a confining layer exists that is capable of preventing the movement of fluids into strata containing protected water.

(e) If an operator has reason to believe that hydraulic fracturing operations have impacted its well(s), the operator shall report the occurrence to the [STATE REGULATOR] within 24 hours of discovery. If the impact is significant and creates a well or surface impact situation, the affected operator must notify the operator performing fracture treatment at the same time.

4.5 **Post-Treatment Report.**

(a) Within thirty (30) days following the conclusion of the hydraulic fracturing treatment and other completion activities on a well, operator shall prepare and submit to [STATE REGULATOR] a report, on a form approved by [STATE REGULATOR], containing the following information:

- (i) The casing and cement report described in Section 3.2(j), that shall include the determined depth of the top of cement for each casing string, hole size, the amount and location of centralizers and the method used to make the determinations;
- (ii) Any cement evaluation or temperature survey log required under Article III;
- (iii) Inclination and directional surveys;
- (iv) The depths and thicknesses of the geologic formations penetrated and the relevant well log, mud log and, if necessary, other data known about the protected water zones, the intervening zone, anomalous pressure zones, zones with corrosive fluids, lost circulation zones and hydrocarbon strata capable of annular flow;
- (v) A perforation report;
- (vi) A record of a successful pressure test performed pursuant to Section 4.3(a).
- (vii) A summary of any events or conditions reported to [STATE REGULATOR] pursuant to Section 4.4(d), as well as how such events or conditions were remedied.
- (viii) A hydraulic fracturing treatment report on the well that includes the following:
 - (1) The treatment data referenced in Section 4.4(b);
 - (2) The total hydraulic fracturing fluid and proppant volumes used in the well, expressed in gallons and pounds or other units approved by [STATE REGULATOR] and the maximum surface treating pressure observed during the hydraulic fracturing treatment;
 - (3) The hydraulic fracturing fluid information required by [STATE REGULATOR]; and
 - (4) The estimated maximum fracture height, fracture half-length and estimated true vertical depth to the top of the fracture achieved during the hydraulic fracturing treatment, as determined by a three dimensional model acceptable to [STATE REGULATOR] using data collected during the hydraulic fracture treatment.
- (ix) Initial well test information recording daily gas, oil and water rate, and tubing and casing pressure;
- (x) Initial gas analysis, performed by a lab approved by [STATE REGULATOR] for such purpose;

(xi) A wellbore diagram that includes casing and cementing data, perforations and a stimulation summary.

(xii) All cementing and stimulation vendor post-job reports.

(xiii) Abnormal drilling conditions as per Sections 3.4(c), 3.5(c) and 3.6(c) not otherwise reported.

(b) In addition to the information provided in Section 4.5(a)(i)-(xiii) above, for minimum separation wells, the operator shall also submit:

(i) The results of the confining layer analysis undertaken pursuant to Section 4.3(f)(ii);

(ii) The results of the hydraulic fracture treatment design analysis undertaken pursuant to Section 4.3(f)(v);

(iii) A post hydraulic fracturing treatment analysis using the same realistic model as used under Section 4.3(f)(iv) and actual data from the hydraulic fracturing treatment, including the calculated fracture length and fracture height for the hydraulic fracture treatment; and

(iv) The results of the cement evaluation log run pursuant to Section 4.3(g).

4.6 **Approved Hydraulic Fracturing, Perforation and/or Logging Contractors.**

(a) In order to comply with this Article, when utilizing an HF service company or other contractors to perform hydraulic fracturing, perforation, and/or logging services in connection with the completion of a well, operators shall utilize only those contractors approved by [STATE REGULATOR]. HF service companies or contractors who seek to perform hydraulic fracturing, perforation and/or logging services, or operators may apply with [STATE REGULATOR] for designation as approved contractors.

(b) An HF service company, contractor or operator seeking designation as an approved contractor by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform such hydraulic fracturing, perforating, and/or logging services in compliance with this rule.

(c) [STATE REGULATOR] shall either approve or deny the application to be designated as an approved contractor. If [STATE REGULATOR] does not recommend approval, or denies the application, the applicant may request a hearing on its application.

ARTICLE V

WELL OPERATIONS – PRODUCTION AND WELL MONITORING

5.1 **Scope of Article.** It is the intent of all provisions of this Article that an operator monitor each producing well to identify any potential problems with a well which could endanger any underground source of protected water or pose a health, safety, or environmental risk. [STATE REGULATOR] shall administer this Article consistent with this intent. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

5.2 **Production and Well Monitoring.**

(a) Operator shall determine Maximum Allowable Operating Pressure (MAOP) and Upper Threshold Pressure (UTP) for each annular pressure on every well as per API RP 90-2 (Annular Casing Pressure Management for Onshore wells) prior to initiating production.

(b) Operator shall monitor and measure the performance of each producing well and submit production reports on a monthly and annual basis, or at such other regular intervals as [STATE REGULATOR] may establish. Production reports shall include the amount of gas, oil and water produced per reporting period.

(c) For the first thirty days of operation, operator shall monitor and record the amount of gas, oil and water produced per day and flowing or shut-in tubing pressure and all annular casing pressures for each producing well on a daily basis. All other wells shall be monitored for these parameters at least weekly and such information shall be recorded. Operator shall keep these records for a minimum period of five (5) years after they are created and for any longer time period and in such form (e.g., electronic) as specified by [STATE REGULATOR].

(d) Operator shall conduct and report to [STATE REGULATOR] quarterly tests of each producing well, or other such interval as [STATE REGULATOR] may establish. Such tests shall record the amount of gas, oil, water produced per day, and flowing or shut-in tubing pressure and all annular casing pressures.

(e) Upon observation, operator shall report to [STATE REGULATOR], as soon as reasonably possible, (i) any annular casing pressure that is above the UTP as per Section 5.2(a), (ii) any annular pressures in excess of 70% of the API rated minimum internal yield or collapse strength of the casing, and (iii) any surface casing pressures that exceed known hydrostatic pressure at the casing shoe or a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet), and shall take immediate action to remedy annular overpressurization. In addition, operator shall perform diagnostic testing to determine if the casing pressure is sustained, which may include a bleed down and build up test. If diagnostic testing reveals sustained casing pressure, the results shall be reported to [STATE REGULATOR], and upon request of [STATE REGULATOR], the operator shall develop and implement a pressure

management plan consistent with API RP 90-2 (Annular Casing Pressure Management for Onshore Wells).

(f) The wellhead, tree, and related surface control equipment shall be maintained and tested to ensure pressure control is maintained throughout the life of the well. All annular valves shall be accessible from the surface or shall be left open and be plumbed to the surface with working pressure gauges. Operator shall install a properly functioning pressure relief device on any casing by casing annulus, unless [STATE REGULATOR] approves otherwise. The maximum set pressure of a surface casing pressure relief device shall be determined in accordance with Section 5.2(a) above based on the MAOP of each annulus. Operator shall report all pressure releases from pressure relief devices to [STATE REGULATOR] within 24 hours of detection. If practical, operator shall tie in the pressure relief flow into sales or a flare stack to minimize atmospheric release of natural gas.

(g) In addition to the elements as outlined in Section 5.2(c), operator shall monitor via visual inspection its producing wells at least weekly for any corrosion, equipment deterioration, hydrocarbon release or changes in well characteristics that could potentially indicate a deficiency in the wellhead, tree and related surface control equipment, production casing, intermediate casing, surface casing, tubing, cement, packers or any other aspect of well integrity necessary to ensure isolation of any underground sources of protected water and prevent any other health, safety, or environmental issue.

(h) If operator has cause to suspect a deficiency, operator shall notify [STATE REGULATOR] and immediately take action to remedy the deficiency, which may require operator to perform diagnostic testing on the well to determine whether a deficiency does exist and the best method of repair.

(i) If diagnostic testing is required, such testing shall be done as soon as is reasonably practical after operator has cause to suspect a deficiency, and if the testing reveals that a deficiency has occurred then operator shall (a) promptly take all appropriate measures to prevent contamination of protected water and otherwise protect the environment, and (b) promptly commence remedial operations that are designed to repair the deficiency.

(ii) Within 30 days of completion of remedial operations, operator shall report the results of the operations to [STATE REGULATOR].

(iii) If operator is not able to effectively repair the deficiency and/or implement a pressure management plan to ensure the protection of all underground sources of protected water and the environment, operator shall be required to immediately plug and abandon the well in accordance with the requirements of Article VI.

ARTICLE VI

PLUGGING AND WELL ABANDONMENT

6.1 **Scope of Article.** This Article governs the process of plugging and abandoning hydraulically fractured wells. The intent of this Article is to ensure that operators plug wells in an effective manner that adequately protects groundwater and other natural resources, public health and safety, and the environment. [STATE REGULATOR] shall administer this Article consistent with this intent. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

6.2 **Application to Plug an Abandoned Well.**

(a) Operator shall submit an application to [STATE REGULATOR], on a form approved by [STATE REGULATOR], of its intention to plug any well over which [STATE REGULATOR] has jurisdiction prior to plugging. Operator's application shall be submitted and approved by [STATE REGULATOR] prior to the beginning of plugging operations in accordance with the requirements of this Article VI. The application to plug an abandoned well must include:

- (i) the reason(s) for abandoning the well;
- (ii) the date that the well was last produced, including rates and types of fluids;
- (iii) a current well diagram showing the type, age, condition (including any known integrity problems) and placement of cement, casing, tubing, perforations, and any other mechanical devices (e.g. plugs, packers);
- (iv) data to verify the tops and bottoms of water and hydrocarbon zones;
- (v) a proposed plugging procedure, including the manner of placement, kind, size, and location by measured depth of existing and proposed plugs; and
- (vi) the proposed timing for plugging and abandonment.

(b) [STATE REGULATOR] shall review and approve the application to plug and abandon in a manner so as to accomplish the purposes of this Article. [STATE REGULATOR] may approve, modify, or reject the operator's application. If the proposal is modified or rejected, operator may request a review by [STATE REGULATOR]. If the proposal is not administratively approved, operator may request a hearing on the matter. After hearing, [STATE REGULATOR] shall recommend final action to operator to plug and abandon the well as per this article.

(c) Operator shall not commence plugging operations until the proposed procedure has been approved by [STATE REGULATOR], and notice has been given in accordance with applicable requirements governing such plugging operations. The duty of operator to properly

plug the well ends only when operator has properly plugged the well in accordance with the requirements of [STATE REGULATOR] approved application to plug and abandon the well.

(d) Operator shall serve notice on the surface owner of the well site tract, the current resident if different than the surface owner, and the mineral owner, no later than fifteen (15) days before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. If the operator has attempted to provide actual notice and if the operator has drilled a dry hole or has an imminent threat to human health, public safety, or the environment, the operator can proceed with plugging and abandonment without having the rig wait 15 days for notice to become effective.

6.3 **Commencement of Plugging Operations, Extensions, and Testing.**

(a) Plugging operations on each dry well shall be completed within no later than thirty (30) days after drilling operations are completed, unless an application for suspended service is submitted and approved by [STATE REGULATOR] confirming that plans are in place to convert or use the well for another purpose.

(b) Plugging operations on each inactive well shall be completed within 180 days of taking the well out of service, or such other term approved by [STATE REGULATOR], unless an application for suspended status is submitted and approved by [STATE REGULATOR] to use the well for another purpose or unless the well poses a health, safety or environmental threat in which case it must be immediately plugged and abandoned.

(c) A well may be approved for suspended status for a period not to exceed one year.

(i) The application for suspended status must demonstrate to [STATE REGULATOR] that the well:

- (1) is mechanically sound;
- (2) will not allow the migration of fluids;
- (3) will not damage protected water or producing or potentially productive formations;
- (4) will not impair the recovery of oil or gas;
- (5) is secure, safe, and not a threat to public health;
- (6) has future utility as an exploratory, development, or service well;
- (7) is a viable candidate for redrilling or well work;

(8) is located on a drill site with active producing or service wells such that its condition is actively and routinely monitored (if this is not the case a monitoring plan for the well during the 12 month suspension period shall be submitted to [STATE REGULATOR]);

(9) is in compliance with all provisions of this chapter and any order, stipulation, or permit issued by [STATE REGULATOR]; and

(10) the operator has the right to continue operating the well

(ii) The application shall also include:

(1) wellbore diagrams illustrating the current mechanical configurations of the well;

(2) the proposed configuration for the well during suspension (if different from the current configuration); and

(3) information on casing, tubing, and annular pressures, and at [STATE REGULATOR's] request, measurements of annular fluid levels.

(iii) An application to suspend the well for a period of up to one year shall be submitted to [STATE REGULATOR] within 7 days of dry hole verification, and within 30 days of inactive well status.

(iv) A suspended well shall be redrilled or worked over within one year from the date of suspension approval or be plugged and abandoned, except that additional one year suspension approvals may be granted by [STATE REGULATOR] if an application meeting the requirements of 6.3(c)(i) and (ii) is submitted at least 60 days prior to the expiration of a suspension period. Otherwise the well shall be plugged and abandoned at the end of the suspension period.

(v) The application will be processed by [STATE REGULATOR] within 7 days of application receipt for a dry hole and 30 days of application receipt for an inactive well.

(vi) A delinquent inactive well, or a well that is determined to be a health, safety, or environmental threat is not eligible for suspended status application or approval.

(vii) The operator of a suspended well shall maintain the integrity and safety of the well and surrounding location. Operator shall inspect the well site after the date of suspension at such intervals as may be established by [STATE REGULATOR] and perform and record a pressure test prior to suspending the well, and at least every three years thereafter while the well remains in suspended status. In the event it is not possible to perform a pressure test, [STATE REGULATOR] may permit operator to monitor the fluid level in the well annually to confirm that the fluid level in the well is at least 200'

below the depth of protected water. Operator shall report the results of the pressure test or fluid level test to [STATE REGULATOR] within 30 days of conducting those tests on a form approved by [STATE REGULATOR].

(d) [STATE REGULATOR] may revoke a plugging extension if the operator of the well that is the subject of the extension (i) fails to maintain the well and all associated facilities in compliance with applicable law and the terms and conditions of the application for well suspension (ii) fails to maintain a current and accurate organizational report or other similar filing on file with [STATE REGULATOR], (iii) fails to provide [STATE REGULATOR], upon request, with evidence of a continuing good faith claim to operate the well, or (iv) fails to obtain or maintain required financial security as required by [STATE REGULATOR].

(e) If [STATE REGULATOR] declines to grant or continue a plugging extension or revokes a previously granted extension, operator shall either return the well to active operation or, within thirty (30) days of receiving written notice of [STATE REGULATOR's] decision, either file an application for a permit to plug the well or request a hearing on the matter.

(f) Plugging operations on delinquent inactive wells shall commence under the plugging permit or within a shorter timeframe established by [STATE REGULATOR]. [STATE REGULATOR] may levy a penalty of [_____] for delinquent inactive well plugging and abandonment delay and [STATE REGULATOR] may require additional environmental monitoring to verify that the plugging and abandonment delay did not result in contamination of surface or subsurface water, injury to the public health, or pollution of other natural resources.

(g) [STATE REGULATOR] shall conduct an investigation of any well that has been found to be causing or is likely to cause the pollution of surface or subsurface water or if liquid or gaseous hydrocarbons or other formation fluid is leaking from the well in quantities or volumes that [STATE REGULATOR] determines can reasonably be anticipated to pose a health, safety, or environmental threat. [STATE REGULATOR] shall notify the owner of any property that may be adversely affected by such pollution. [STATE REGULATOR] shall notify the surface owner if there is a delinquent well requiring plugging and abandonment.

(h) [STATE REGULATOR] may plug or replug any dry or inactive delinquent well as follows:

(i) After notice and hearing, if the well has not been plugged and abandoned in accordance with the time frames and requirements of this chapter;

(ii) Without notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if liquid or gaseous hydrocarbons or other formation fluid is leaking from the well or if the well poses any other health, safety, or environmental threat, and:

(1) Neither the operator nor any other entity responsible for plugging the well can be found; or

(2) Neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(iii) Without a hearing if the well is a delinquent inactive well and:

(1) [STATE REGULATOR] has sent notice of its intention to plug the well as may be required; and

(2) the operator did not request a hearing within the applicable period specified in such notice.

(iv) Without notice or hearing, if:

(1) [STATE REGULATOR] has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(2) The well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(i) [STATE REGULATOR] may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to Section 6.3(h).

(j) [STATE REGULATOR] may require a well to be immediately plugged if a well construction deficiency is determined during the construction of the well, and [STATE REGULATOR] determines that additional remedial measures will not isolate protected water or remedy any other health, safety, or environmental threat posed by such well.

(k) Operator and [STATE REGULATOR] will keep permanent records for each suspended and plugged and abandoned well, along with all post plugging and abandonment monitoring records. All such records shall be maintained in the event they are needed to develop a re-entry and repair plan if the well leaks post plugging and abandonment.

6.4 **Designated Operator Responsible for Proper Plugging.** The entity that is the most recent [STATE REGULATOR]-approved operator of a well shall be presumed to be the party responsible for properly plugging the well. An operator may rebut this presumption of responsibility at a hearing called by [STATE REGULATOR] for purposes of determining plugging responsibility.

6.5 **General Plugging Requirements.**

(a) Wells shall be plugged to ensure that all formations bearing protected water, hydrocarbons, or geothermal resources are protected, confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface.

(b) All cementing operations during plugging shall be performed under the direct supervision of operator or its authorized representative, who shall be independent of the applicable service or cementing company hired to plug the well. Operator and the cementer shall both be responsible for complying with general plugging requirements and for plugging the well in conformity with the procedure set forth in the approved application to plug and abandon the well.

(c) Cement plugs shall be set to isolate each hydrocarbon strata and the lowermost protected water strata. Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR]. Operator shall verify the placement of the plug required at the base of the deepest protected water stratum by tagging with tubing or drill pipe or by an alternate method approved by [STATE REGULATOR].

(d) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe, subject to approved exceptions by [STATE REGULATOR].

(e) All cement used for plugging shall be of a composition approved by [STATE REGULATOR], and [STATE REGULATOR] may require that specific cement compositions be used in certain situations. Cement must conform to API Specification 10A (Specification for Cement and Material for Well Cementing). [STATE REGULATOR] may require additional cement additives or cement in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area around the well. [STATE REGULATOR] may approve the use of alternate materials if [STATE REGULATOR] deems it appropriate, but [STATE REGULATOR] shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources. Operator shall follow all other quality control and quality assurance requirements for cement installation listed in Article III.

(f) [STATE REGULATOR] may require additional cement plugs to cover and contain any hydrocarbon stratum, or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting is required to ensure that the well does not pose a potential threat of harm to natural resources.

(g) A 50-foot cement plug shall be placed in the top of the well, and casing shall be cut off at least three feet below the ground surface or at such other depth as required by [STATE REGULATOR].

(h) Mud-laden fluid of at least 9.0 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by [STATE REGULATOR]. The mud-laden fluid shall exert a fluid density greater than the highest formation pressure in the interval between the plugs at the time of abandonment. The hole shall be in static condition at the time the cement plugs are placed. [STATE REGULATOR] may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will ensure that the well does not pose

a potential threat of harm to natural resources, public safety, or the environment. [STATE REGULATOR] may approve the use of alternate fluid or material if [STATE REGULATOR] deems it appropriate, but [STATE REGULATOR] shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources, public safety, or the environment.

(i) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except as may be otherwise expressly permitted under law. Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by [STATE REGULATOR].

(j) Operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. If flowlines are left in place, they shall be purged of any liquids, depleted to atmospheric pressure, capped on both ends and any above-ground cathodic protection and equipment associated with the flowline shall be removed. Operator shall close all pits in accordance with applicable [STATE REGULATOR] requirements. [STATE REGULATOR] may grant an extension of not more than an additional 60 days for the removal of tanks, vessels and related piping.

(k) Operator shall notify [STATE REGULATOR] at least 24 hours prior to commencing plugging and well abandonment operations.

(l) Operator shall complete and file with [STATE REGULATOR] a duly verified plugging record on a form approved by [STATE REGULATOR] within thirty (30) days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(m) Within 30 days of an operator completing abandonment requirements for an off-location flowline the operator shall submit a report to the [STATE REGULATOR] which includes the latitude and longitude for the flowline's capped ends.

(n) [STATE REGULATOR] will witness the work, review the 30 day plugging records, and will either issue a plugging and abandonment approval within 30 days or issue a corrective action order. Corrective action must be completed within the timeframe specified in the order, but no later than 30 days from the date of the order. [STATE REGULATOR] may require surface and/or subsurface monitoring programs after the well has been plugged and abandoned if there is any reason to believe that subsurface or surface pollution occurred or may persist. [STATE REGULATOR] reserves the right to require the operator to re-enter the well and complete additional remediation or plugging and abandonment work in the future, so long as operator has the legal right to enter upon the leased premises to conduct such operations.

6.6 **Plugging Requirements for Wells with Surface Casing.**

(a) When insufficient surface casing was set to protect all protected water strata and all hydrocarbon strata, and such strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug or plugs shall be placed centered opposite the top of each hydrocarbon stratum and the base of the deepest protected water stratum. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the top of each hydrocarbon stratum or abnormally geopressured strata, and the base of the deepest protected water stratum. The plug across the deepest protected water stratum shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug or plugs shall be set across the shoe of the surface casing and any multi-stage cementing tool. Each such plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above and below the shoe or multi-stage cementing tool.

(b) When sufficient surface casing has been cemented to isolate all protected water, a cement plug shall be placed across the shoe of the surface casing and across any multi-stage cementing tool. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above the shoe and at least 100 feet below the shoe.

(c) If surface casing has been set deeper than 200 feet below the base of the deepest protected water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest protected water stratum. This plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the base of the deepest protected water stratum.

(d) Plugs shall be set as necessary to separate multiple protected quality water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

6.7 **Plugging Requirements for Wells with Intermediate Casing.**

(a) For wells in which the intermediate casing has been cemented through all protected water strata and all hydrocarbon strata, a cement plug or plugs meeting the requirements of Section 6.6(a) shall be placed inside the casing and centered opposite the base of the deepest protected water stratum, but extend no less than 50 feet above and below the base of the deepest protected water stratum. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest protected water stratum. In addition, a cement plug or plugs shall be set across the shoe of the intermediate casing, if it is open to the wellbore, and any multi-stage cementing tool. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe or multi-stage cementing tool, as applicable.

(b) For wells in which intermediate casing is not cemented through all protected water strata and all hydrocarbon strata, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(c) Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

6.8 Plugging Requirements for Wells with Production Casing.

(a) For wells in which the production casing has been cemented to isolate all protected water strata and all hydrocarbon strata, and a cement evaluation tool has been run and the cement is verified to be in good condition and determined to be a barrier to fluid and gas migration in the annulus in accordance with Section 3.6(c), cement plugs meeting the requirements of Section 6.6(a) shall be placed inside the casing and centered opposite the top or the uppermost hydrocarbon stratum and the base of the deepest protected water stratum and across any multi-stage cementing tool. If annular cement integrity cannot be confirmed, [STATE REGULATOR] will require the annulus to be squeeze cemented. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the top of the uppermost hydrocarbon stratum and the base of the deepest protected water stratum.

(b) For wells in which the production casing has not been cemented through all protected water strata and all hydrocarbon strata and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through the casing perforations.

(c) [STATE REGULATOR] may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. Such cement plug may be placed as pursuant to 6.5(d) or using a dump bailer. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(d) Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

6.9 Plugging Requirements for Wells with Screen or Liner.

(a) The screen or liner shall be removed from the well, unless determined by [STATE REGULATOR] to be technically infeasible.

(b) If the screen or liner is not removed, a cement plug in accordance with Section 6.6(a) shall be placed at the top of the screen or liner.

6.10 Plugging Requirements for Wells with Formation Pressure Problems.

(a) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in Section 6.6(a) above.

(b) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation and abnormally geo-pressured strata, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

6.11 **Plugging Horizontal Wells.** All plugs in horizontal wells shall be set in accordance with Section 6.6(a). The productive horizon isolation plug shall be set from a depth of 50 feet (measured depth) below the top of the productive horizon to a depth of either (i) 50 true vertical feet above the top of the productive horizon, or (ii) if the production casing is set above the top of the productive horizon, 50 true vertical feet above the production casing shoe. In accordance with Section 6.5(f), [STATE REGULATOR] may require additional plugs.

6.12 **Plugging of Minimum Separation Wells.** In addition to the plugging requirements for wells that are not classified as minimum separation wells, for minimum separation wells a plug shall be set extending 50 feet below the top of the productive horizon to 50 true vertical feet above the top of the intervening zone. The plug shall be evidenced by tagging with tubing or drill pipe.

6.13 **Marking the Location of a Plugged Well.** Upon the completion of plugging or replugging a well, operator shall erect over the plugged well a permanent marker of concrete, metal, plastic, or equally durable material. The marker must extend at least 4 feet above the ground surface and enough below the surface to make the marker permanent. Cement may be used to hold the marker in place provided the cement does not prevent inspection of the adequacy of the well plugging. The permit or registration number shall be stamped or cast or otherwise permanently affixed to the marker. In lieu of placing the marker above the ground surface, the marker may be buried below plow depth and shall contain enough metal to be detected at the surface by conventional metal detectors.

6.14 **Approved Cementers.**

(a) In order to comply with this Article, when conducting plugging operations which require cementing, operators shall utilize only those cementers approved by [STATE REGULATOR]. Cementing companies, service companies, or operators may apply with [STATE REGULATOR] for designation as approved cementers. Such approval will be granted by [STATE REGULATOR] upon a showing by the applicant of its ability to mix and pump cement or other alternate materials as approved by [STATE REGULATOR] in compliance with this rule.

(b) A cementing company, service company, or operator seeking designation as an approved cementer by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as the [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform cementing operations in compliance with this rule, which may include, but not limited to, the following:

(i) A list of the applicant's qualifications and experience, including qualifications of the personnel that will supervise the mixing and pumping operations; and

(ii) An inventory of the type of equipment to be used to mix and pump cement.

(c) [STATE REGULATOR] shall either approve or deny the application to be designated as an approved cementer. If [STATE REGULATOR] does not recommend approval, or denies the application, the applicant may request a hearing on its application.