ARKANSAS

OIL AND GAS COMMISSION

GENERAL RULES

As of May 08, 2022

FOREWORD

This publication contains the Commission Rules of statewide application. Special rules pertaining to individual oil, gas, or salt water fields and pools are not included but should be consulted.

In using this publication one should be aware that there is a considerable body of statutory law in Arkansas that must be consulted in evaluating an oil and gas matter.

This statutory law is not set out in full herein. The reader should refer to Arkansas Code, Annotated, Title 15, Chapter 72, for the statutory law.

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ELECTRONIC COPIES OF REQUIRED FORMS

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GENERAL RULE A – ADMINISTRATIVE

RULE A-1: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE A-2: GENERAL HEARING PROCEDURES

a) Execution and Filing

1) All applications, except for applications filed by the Director, shall be in writing and state the interests of the application and the general nature of the order requested. Fourteen copies of the application, including exhibits, shall be filed with the Commission Director's office located in Little Rock, Arkansas ("Director's Office"). The application shall be deemed filed when it is received by the Director's Office.

2) All fourteen (14) copies of the applications, including exhibits, except for those filed by the Director, must be received in the Directors Office at least twenty (20) days prior to the first day of regularly scheduled hearing. If the applicant or his/her representative files an electronic version (a .pdf file labeled by the assigned docket number) of the application, including exhibits, on an electronic storage device approved by the Director a minimum of twenty (20) days prior to the first day of the regularly scheduled hearing, the fourteen (14) copies of the applications, including exhibits must be received in the Director's office eighteen (18) days prior to the first day of the regularly scheduled hearing.

3) Every application shall be signed by the applicant or his/her representative and his/her address shall be stated thereon. The signature of the applicant or his/her representative constitutes a certificate by him/her that he/she has read the petition and that to the best of his/her knowledge, information and belief there is good ground to support the same.

4) Unless otherwise provided by General Rule of the Commission, each application, except for applications filed by the Director, shall be accompanied by a five hundred dollar ($500.00) filing fee made payable to the Arkansas Oil and Gas Commission.

5) The applicant shall also submit a check payable to the Arkansas Oil and Gas Commission in an amount approved by the Commission, not to exceed two dollars ($2.00) per name of persons named in the application, whose address are known as well as addresses for other persons that the applicant seeks to provide a copy of the order. The applicant shall also provide mailing labels for each person named in the application whose address is known, as well as any other person that the applicant seeks to provide a copy of the order. If the address of the person is unknown, the Applicant shall provide a statement to that affect. All mailing labels shall be provided within three (3) days after the date of the hearing.

6) If after the application is filed, and prior to the hearing date, the Director finds the application deficient relative to the requirements of subsections a) 1) through 4) above, the Director shall return the application to the applicant with a statement as to the deficiencies.

7) If after the application is filed, and prior to the hearing date, the Director determines that additional facts, data, records, or other information are necessary to fully evaluate the application, the Director may require the applicant to submit such necessary facts, data, records or other information.

8) Amendments may be filed at the time of the hearing. However, any amendments filed prior to the hearing date shall be submitted at least ten (10) days prior to the hearing date, and contain a written statement or a clear indication as to what the amendment is being amended. Any application that is substantially amended, as determined by the

Commission, regardless of the time of the amendment, may be continued until the next hearing of the Commission.

b) Notice of Hearing

1) The Applicant shall prepare a notice of hearing which shall be issued in the name of the Arkansas Oil and Gas Commission. Such notice shall include a statement pertaining to the legal authority for the hearing; the name of the applicant; the legal description of the property or unit; a statement of the requested action; a listing of interested parties; the time, date and location of the hearing; the Commission assigned docket number; and the contact information of the Commission offices. The notice shall also state that any interested person may file an entry of appearance in the hearing by submitting such entry of appearance in writing to the Hearing Officer or Director, and that thereafter such person shall be deemed a party of record in the proceeding.

2) Unless otherwise provided by the Brine Act found in Ark. Code Ann. § 15-76-201 *et. seq*. or General Rule of the Commission, the Applicant shall serve such notice in the following manner:

A) By mailing such notice by U.S. Postal service, first-class mail, directed to all interested parties at their last known addresses at least ten (10) days prior to the date of the hearing, but not more than thirty (30) days prior to the date of the hearing; and

B) By publication of such notice for at least one (1) day, with the notice appearing at least ten (10) days prior to the date of the hearing, but not more than thirty (30) days prior to the date of the hearing, in the newspaper of general circulation published in each county containing some portion of the land identified in the application.

c) Emergency Hearings

In the event an emergency is found to exist by the Commission which in its judgment requires the making, changing, renewal or extension of an order or special rule, without first having a hearing, such emergency order shall have the same validity as if a hearing with respect to the same had been held after due notice. The emergency order permitted by this section shall remain in force until the date of the next regular Commission hearing set to be held after the emergency rule or order was issued, or sixty days from its effective date in accordance with the Brine Act found in Ark. Code Ann. § 15-76-307, and, in any event, it shall expire when any order made after due notice and hearing with respect to the subject matter of such emergency order becomes effective.

d) Pre-Hearing Conferences

1) Upon his/her own motion, or the motion of a party of record, the Hearing Officer, as designated by the Commission, may convene a meeting of the parties or their counsel in order to:

A) Simplify the factual and legal issues presented by the hearing request;

B) Receive stipulations, admissions of fact and the contents and authenticity of documents;

C) Exchange lists of witnesses the parties intend to have testify and copies of all documents the parties intend to introduce into evidence at the hearing; and

D) Discuss and resolve such other matters as may tend to expedite the disposition of the hearing request and to assure a just conclusion thereof.

2) Pre-hearing conferences may be held by telephone conference if such procedure is acceptable to all parties.

e) Hearings

1) Every hearing shall be held on a date and at a location established by the Commission, and conducted by a Hearing Officer designated by the Commission. The Hearing Officer shall take all necessary actions to avoid delay, to maintain order and to develop a clear and complete record, and shall have all powers necessary and appropriate to conduct a fair hearing and to render a decision on the petition, including but not limited to the following:

A) To administer oaths and affirmations;

B) To receive relevant evidence;

C) To regulate the course of the hearing and the conduct of the parties and their counsel therein;

D) To consider and rule upon procedural requests;

E) To examine witnesses and direct witnesses to testify, limit the number of times any witness may testify, limit repetitive or cumulative testimony and set reasonable limits on the amount of time each witness may testify; and

(F) To require the production of documents or subpoena the appearance of witnesses, either on the Hearing Officer's own motion or for good cause shown on motion of any party of record. The Hearing Officer may require that relevant documents be produced to any party of record on his/her own motion or for good cause shown on motion of any party of record.

2) Every person appearing shall enter his/her appearance by stating his/her name and address. Thereafter, such person shall be deemed a party of record.

3) All participants in the hearing shall have the right to be represented by an attorney licensed to practice law in the State of Arkansas. An attorney appearing in a representative capacity in any proceeding hereunder shall file a written notice of appearance identifying his or her name, address and telephone number, and identifying the party represented.

4) The Hearing Officer shall allow all parties to present statements, testimony, evidence and argument as may be relevant to the proceeding.

5) The Director, or his/her designee, may appear at any public hearing and shall have the opportunity to question parties or otherwise elicit such information as is necessary to reach a decision on the application.

6) Preliminary Matters: Where applicable, the following shall be addressed prior to receiving evidence:

A) The applicant may offer preliminary exhibits, including documents necessary to present the issues to be heard, notices, proof of publication and orders previously entered in the cause.

B) Rulings may be made by the Hearing Officer on any pending motions.

C) Any other preliminary matters appropriate for disposition prior to presentation of evidence.

7) Every hearing shall be conducted in accordance with the Commission's rules and applicable laws of this State.

f) Evidence

1) Admissibility: A party shall be entitled to present his/her case by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross-examination as may be required for a full and true disclosure of the facts. Any oral or documentary evidence may be received, but the presiding Hearing Officer may exclude evidence which is irrelevant, immaterial or unduly prejudicial or repetitious. However, the erroneous ruling on the admissibility of evidence shall not of itself invalidate any rule or order.

2) Official Notice: Official notice may be taken of any material fact not appearing in evidence in the record if the circuit courts of this State could take judicial notice of such fact. In addition, notice may be taken of generally recognized technical or scientific facts within the Commission's specialized knowledge.

3) Order of Proof: The applicant shall open the proof. Other parties of record shall be heard immediately following the petitioner. The Hearing Officer or Director or his/her designee, as well as any Commissioner may examine any witnesses. In all cases, the Hearing Officer shall designate the order of proof and may limit the scope of examination or cross-examination.

4) Briefs: The Hearing Officer may require or allow parties to submit written briefs to the Hearing Officer within 10 days after the close of the hearing or within such other time as the Hearing Officer shall determine as being consistent with the Commission's responsibility for an expeditious decision.

g) Recording of Proceedings; Testimony

The Commission shall provide a certified court reporter to take down the testimony and preserve a record of all proceedings at the hearing. Any person testifying shall be required to do so under oath. However, relevant unsworn statements, comments and observations by any interested person may be heard and considered by the Commission as such and included in the record.

h) Postponement or Continuance of Hearing

Any hearing may be postponed or continued for due cause by the Hearing Officer upon his/her own motion or upon the motion of a party to the hearing. A motion filed by a party to the hearing shall set forth facts attesting that the request for continuance is not solely for the purpose of delay. All parties involved in a hearing shall avoid undue delay caused by repetitive postponements or

continuances so that the subject matter of the hearing may be resolved expeditiously. The Applicant may postpone or continue the hearing of an application for three consecutive regularly scheduled Commission meetings without prior approval of the Hearing Officer. After the third consecutive postponement, the application shall be dismissed, unless the Hearing Officer allows an exception for due cause, and the applicant shall be required to re-file in accordance with applicable General Rules in order for an application to be scheduled for a hearing.

i) Default - Failure to Appear.

If a party, after proper service of notice, fails to appear at the pre-hearing conference or at a hearing, and if no continuance is granted, the Commission may then proceed to make its decision in the absence of such party. If the failure to appear at such pre-hearing conference or hearing is due to an emergency situation beyond the parties' control, and the Commission is notified of such situation on or before the scheduled pre-hearing conference or hearing, the Hearing Officer may continue or post-pone the pre-hearing conference or hearing. Emergency situations include sudden unavailability of counsel, sudden illness of a party or his representative, or similar situations beyond the parties' control.

j) Administrative Issuance of Default Integration Order for Certain Unleased Mineral Interests.

1) The Director is authorized to issue an administrative order integrating unleased mineral interest owners in any unit where there is not a well capable of production if all of the following criteria are met:

A) An application is filed with the Director that includes all of the information required in General Rule A-3 b) 2) A) though G);

B) Each mineral interest sought to be integrated is less than one (1) net mineral acre;

C) The cash bonus and royalty rate requested by the applicant are equal to or greater than the highest and/or best cash bonus and royalty terms that the applicant has knowledge of that have been offered and accepted, or contracted for, for any acreage within the unit(s) where the well is located (as defined in Section (a)(2) of General Rule B-3), including any acreage within the unit(s) subject to leases or other agreements with a fee mineral owner covering lands located in more than one unit.

D) The applicant specifies which Model Form Operating Agreement approved by the Commission it seeks to use, with Paragraph III.1.A.(1) of the COPAS:

i) Not to exceed more than $7,500.00 for a drilling well rate and $750.00 dollars for a producing well when the proposed well is a dry natural gas well; or

ii) Not to exceed more than $4,500.00 for a drilling well rate and $450.00 dollars for a producing well when the proposed well is a liquid hydrocarbon well.

E) The applicant provides an affidavit or other documentary evidence to support a reasonable risk factor penalty, and the requested risk factor does not exceed 400%.

F) No earlier than ten (10) business days prior to, and no later than three (3) business days prior to, the filing of the application, the applicant shall send to affected mineral interests owners, whose mailing addresses may reasonably be ascertained, a notice of the application's filing and verify such mailing by affidavit, setting out the names and addresses of all owners and the date(s) of mailing.

G) The applicant shall also submit proof of publication of such notice of the applications in a newspaper of general circulation within the county or counties within which the unit is located that appeared at least one time no earlier than ten (10) days prior to filing the application, and no later than the date of filing the application.

H) Any owner, so noticed shall have the right to object to the granting of such application within fifteen (15) days after the date of receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed, then the applicant shall be promptly furnished a copy and such application shall be denied, unless the objection is withdrawn within the original fifteen (15) day time period after receipt of the application. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional fee is required.

I) If no timely objection is received, or if one is received and withdrawn within the original fifteen day time period after receipt of the application, the Director is authorized to approve the application administratively.

2) An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties, in order to prevent waste, or for any other reason. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for referral to the full Commission for determination. If the application is referred under this section, the applicant shall file a request for a hearing, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

3) If the Applicant has satisfied all applicable provisions, the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection j)1)H) above, the application shall be approved and an administrative default order shall be issued by the Director.

k) Voting

1) In order for the Commission to adopt a motion approving an application as applied for, or as amended by either the applicant of a Commissioner, there must be:

A) A quorum present;

B) A majority of the votes cast must be in favor of the motion outlining the proposed order; and

C) At least five (5) votes cast must be in favor of the motion outlining the proposed order.

2) If a motion approving the application as applied for, or as modified by either the applicant or a Commissioner does not receive the votes required in subparagraphs 1) A) through C) above, and no subsequent or substitute motion receives the votes required in subparagraphs 1) A) through C) above, then the application shall be deemed to be denied by the Commission.

3) If an application is deemed to be denied by the Commission in accordance with subparagraph i) 2) above, the Commission shall enter an order of denial, which may be appealed as a final decision under the Arkansas Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 *et. seq.*

4) Nothing in this subparagraph shall limit the Commission's authority to continue any application for due cause.

l) Commission's Order--Final Administrative Decision

Within 30 days of the close of the hearing record, the Commission shall issue findings of fact, conclusions of law and final administrative decision of the Commission signed by the Director. The Commission shall have continuing jurisdiction for the purposes of enforcement, and/or modifications or amendments to the provisions of all orders. Any appeals shall be governed by the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 *et. seq.*

m) Notice of Order--Recordation

Within 30 days after an order has been issued, a copy of such order shall be mailed by the Commission to each interested party at his/her last known address or his/her attorney of record, and filed in accordance with the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 *et. seq.*

n) Official Record

In every case of adjudication, the official record shall be complied in accordance with the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 *et. seq.*

(Source: 1992 rule book; amended April 13, 2008; amended June 5, 2009; amended October 24, 2009; amended July 1, 2016)

RULE A-3: ADDITIONAL REQUIREMENTS FOR SPECIFIC TYPES OF HEARINGS

a) Abandoned Well and Emergency Response Hearings

1) Unless otherwise specified below, General Rule A-2 shall apply to all abandoned well and emergency response hearing proceedings pursuant to Ark. Code Ann. § 15-72-217.

2) The Director shall only provide notice to the permit holder named in the application, in accordance with General Rule A-2 (b) (2).

3) The Director shall have the burden of proof at the hearing. A decision shall be supported by a substantial evidence standard.

b) Integration Hearings

1) Unless otherwise specified below, General Rule A-2 shall apply to all drilling unit integration proceedings heard by the Commission.

2) Commencement of Action

Where the oil or gas rights within a drilling unit are separately owned and the owners of those rights have not voluntarily agreed to integrate or pool those rights to develop the oil or gas, an owner may petition the Commission for an order integrating those rights, pursuant to Ark. Code Ann. § 15-72-302 and §15-72-303. The application for an order integrating interests shall contain the following:

A) The name and address of the applicant;

B) The applicant's reasons for desiring to integrate the separately owned interests;

C) A legal land description of the drilling unit sought to be established;

D) A geologic report of the area where the proposed drilling unit is to be located indicating the potential presence of reservoirs;

E) If the application is for the integration of an exploratory drilling unit, as contemplated by Ark. Code Ann. § 15-72-302:

i) the names of all owners named in the application who have not agreed to integrate their interests in the right to drill and produce oil or gas, or both, in the proposed drilling unit as of the date of filing the petition, as disclosed by the records in the office of the clerk for the county or counties in which the drilling unit is situated, and;

ii) a statement that the persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas or both, from the total proposed unit agree thereto at the time of the filing of the application;

F) If the application is for the integration of an established drilling unit, as contemplated by Ark. Code Ann. § 15-72-303, and created in accordance with applicable Commission Orders or General Rules; the names of all owners named in the application who have not agreed to integrate their interests in the right to

drill and produce oil or gas, or both, in the proposed drilling unit as of the date of filing the petition, as disclosed by the records in the office of the clerk for the county or counties in which the drilling unit is situated;

G) Unleased mineral owners.

i) A resume of efforts showing that the applicant has exercised due diligence, to locate each unleased mineral owner, and that a bona fide effort was made to reach an agreement with each owner as to how the unit would be developed, as follows:

aa) Due diligence, regarding non-industry owners (persons who are not actively involved in the oil and gas business) means, except for good cause shown, to be determined at the discretion of the Commission, that the Applicant attempted to contact said owners and that bona fide efforts to reach an agreement commenced at least sixty (60) days prior to the date of the hearing; and that there are sufficient contacts to show that the Applicant has exhausted all reasonable efforts to reach an agreement. However, the Applicant shall not be required to contact an owner that the Applicant is precluded by law from contacting, or an owner who has expressly stated that the Applicant is not to contact said owner.

bb) Due diligence, regarding industry owners (person who as an active business practice are involved in the oil and gas business) means that the Applicant has provided industry owners notice, including an Authorization for Expenditure ("AFE") and Well Proposal, prior to filing the integration application.

ii) An affidavit indicating what the highest and/or best cash bonus and royalty terms that the Applicant has knowledge of that have been offered and accepted, or contracted for, for any acreage within the unit(s) where the well is located (as defined in Section (a)(2) of General Rule B-3), including any acreage within the unit(s) subject to leases or other agreements with a fee mineral owner covering lands located in more than one unit. If this information changes prior to the hearing, the Applicant shall inform the Commission of any changes. If no affidavit is provided prior to or at the time of the hearing, the Applicant shall provide sworn testimony as to the highest and/or best cash bonus and royalty terms that the Applicant has knowledge of that have been offered and accepted, or contracted for, for any acreage within the unit(s) where the well is located (as defined in Section (a)(2) of General Rule B-3), including any acreage within the unit(s) subject to leases or other agreements with a fee mineral owner covering lands located in more than one unit.

H) Uncommitted Leasehold Working Interest Owners.

A resume of efforts showing that the applicant has exercised due diligence, to locate each uncommitted leasehold working interest owner and that a bona fide effort, was made to reach an agreement with each owner as to how the unit would be developed, by providing the uncommitted leasehold working interest owners

notice, including an AFE and Well Proposal, prior to filing the integration application.

I) Any other information relevant to protect correlative rights of the parties sought to be affected by the order.

c) Appeal of Director's Decision.

1) Any interested party may appeal a permit denial, any enforcement action, or rule interpretation decision made by the Director to the Commission.

2) Unless otherwise specified below, General Rule A-2 shall apply to all hearings requested to appeal a decision of the Director.

3) The application to appeal a Director's decision shall be accompanied by a two hundred and fifty dollar ($250.00) filing fee.

d) Exceptional Well Location

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for an application which has been referred to the Commission in accordance with General Rule B-40, or for which General Rule B-40 is not applicable.

2) The application shall include proof of notice to each owner within the unit in which the well is located and within the units offsetting the boundary line or lines, or in the case of wells in uncontrolled fields within the boundaries of mineral lease lines and the offsetting lease(s), which shall be encroached upon by the exceptional well location.

3) If the application has been referred to the Commission in accordance with General Rule B-40, no application fee is required to be submitted with the application.

e) Authority to Commingle and Additional Completions

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for which the applicant has requested a hearing for an application which has been denied in accordance with General Rule D-18 or General Rule D-19, or for which General Rules D-18 or D-19 are not applicable.

2) If the applicant requests the hearing in accordance with General Rule D-18, the application shall include proof of notice to all offset operators in all adjacent units.

3) If the applicant requests the hearing in accordance with General Rule D-19, the application shall include proof of notice to all working interest owners in the subject unit and all offset operators in all adjacent established units including all working interest owners in the offset unit where the operator is the same as the applicant.

f) Establishment of Field Rules

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for the creation of field rules, as provided by General Rule B-38.

2) The application shall include proof of notice to each owner, as defined in Ark. Code Ann. § 15-72-102 (9), within the proposed unit(s) in which the well(s) is/are located and within all units offsetting the boundary line or lines of the proposed unit(s).

3) The application shall include a geologic report of the proposed field, specifying the geologic setting of the proposed field and including at a minimum a completion report of the discovery and other wells located within the proposed field, a type geophysical log from a well(s) in the proposed field and a structure and isopach map of the productive zone(s) within the proposed field.

(Source: 1992 rule book; amended April 13, 2008; amended December 14, 2008; amended July 17, 2009; amended July 1, 2016)

RULE A-4: DEFINITIONS

Unless the context otherwise requires, the words defined shall have the following meaning when found in these rules, to-wit:

ATMOSPHERIC PRESSURE -- shall mean the pressure of air at the sea level, equivalent to about 14.7 pounds to the square inch.

BALANCE -- (Gas) shall mean an instrument used for determining the specific gravity of gases by weighing methods.

BAROMETRIC PRESSURE -- shall mean the pressure or weight of air determined by the use of a barometer at a given point.

"BARREL" or "BARREL OF OIL" -- shall mean 42 United States gallons of oil at a test of 60 degrees Fahrenheit, with deductions for the full percent of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

BLOW-OUT -- shall mean a sudden or violent escape of crude oil or natural gas, as from a drilling well, when high formation pressure is encountered.

BLOW-OUT PREVENTER -- shall mean a heavy casing head control filled with special gates or discs which may be closed around the drill pipe, or which completely closes the top of the casing if the pipe is withdrawn.

BOTTOM HOLE PRESSURE -- shall mean the pressure in pounds per square inch at or near the bottom of an oil or gas well determined at the face of the producing horizon by means of a pressure recovery instrument, adopted and recognized by the oil and gas industry, which can be lowered into the bore of the well. In the case of gas wells or wells having no fluid in the well bore, it shall mean the pressure as calculated by adding the pressure at the surface of the ground to the calculated weight of the column of gas from the surface to the bottom of the hole.

CASING PRESSURE -- shall mean the pressure built up between the casing and tubing when the casing and tubing are packed off at the top of the well.

CASINGHEAD GAS -- shall mean any gas or vapor, or both gas, and vapor, indigenous to an oil stratum and produced from such stratum with oil.

CHRISTMAS TREE -- shall mean an assembly of valves and fittings at the head of the casing of a well to control the flow. Also spoken of as "well head connections."

CIRCULATION -- shall mean the passing of an approved fluid down through the drill stem and up to the surface in the process of rotary drilling in setting casing.

COMBINATION WELL -- shall mean a well productive of both oil and gas in commercial quantities from the same common source of supply and which has sufficient natural gas pressure to cause the gas to enter a pipe line carrying more than atmospheric pressure.

COMMISSION -- shall mean the Arkansas Oil and Gas Commission.

COMMON SOURCE OF SUPPLY -- shall mean the geographical area or horizon definitely separated from any other such area or horizon and which contains, or from competent evidence appears to contain, a common accumulation of oil or gas or both. Any oil or gas field or part thereof which

comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil or gas or both oil and gas.

CONDENSATE -- shall mean the liquid produced by the condensation of a vapor or gas either after it leaves the reservoir or while still in the reservoir. Condensate is often called Distillate, Drips, White Oil, Etc.

CONNATE WATER -- shall mean water which was deposited with the deposition of solid sediments in an oil or gas reservoir and which has not, since its deposition, existed as surface water at atmospheric pressure.

CONSERVATION -- shall mean the conserving, preserving, guarding or protecting the oil and gas resources of the state by obtaining the maximum efficiency with minimum waste in the production, transportation, processing, refining, treating and marketing of the unrenewable oil and gas resources of the state.

CONTROLLED OIL FIELD -- shall mean any common source of supply of crude oil discovered after January 1, 1937, or any field discovered prior to January 1, 1937, provided any pool therein has been discovered after January 1, 1937.

CONTROLLED GAS FIELD -- shall mean any common source of supply of natural gas discovered after January 1, 1937, or any field discovered prior to January 1, 1937, provided any pool therein has been discovered after January 1, 1937.

CONTROLLED PRODUCTION -- shall mean the production of oil or gas or both oil and gas from a controlled oil or gas field.

CORE HOLE -- shall mean a hole drilled below the fresh water level for obtaining geological and structural information without penetrating a known producing formation in the area.

CRUDE OIL -- shall mean petroleum oil, and other hydrocarbons, regardless of gravity, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

CUBIC FOOT OF GAS -- shall mean the volume of gas contained in one cubic foot of space at the standard pressure base and the standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute and the standard temperature base shall be 60° Fahrenheit.

DAY -- shall mean a period of twenty-four (24) consecutive hours from 7:00 a.m. one day to 7:00 a.m. the following day.

DEVELOPMENT -- shall mean any work which actively looks toward bringing in production, such as erecting rigs, building tankage, drilling wells, etc.

DIFFERENTIAL PRESSURE -- shall mean the difference between the tubing pressure and the flow-line pressure; the drop flow-line pressure; the drop in pressure of the fluid in passing through the flow-nipple or choke; in the case of an orifice meter, the difference of the pressures on the up-stream and the down-stream sides of the orifice; a pressure measured with a differential gauge or with a manometer (U-tube); any difference in pressure.

DISTILLATE -- shall mean a product of distillation of the fluid condensed from the vapor driven off in the still, such as gasoline, naphtha, kerosene, and light lubrication oils, the result of distillation of crude oil. Condensate is commonly referred to as distillate.

DIVISION ORDER -- shall mean a written statement, dated, duly signed by the owners and delivered to the purchaser, certifying and guaranteeing the interests of ownership of the production and directing payments according to those interests.

DRY GAS -- shall mean natural gas obtained from sands that produce gas only; or natural gas obtained which does not contain the heavier fractions which may easily condense under normal atmospheric conditions; not casinghead gas.

EDGE WATER -- shall mean water that holds the oil or gas, or both oil and gas, in higher structural position, usually encroaching on a pool as the oil or gas is removed.

FIELD -- shall mean the general area which is underlaid or appears to be underlaid by at least one pool; and "field" shall include the underground reservoir or reservoirs containing crude petroleum oil or natural gas, or both. The words "field" and "pool" mean the same thing when only one underground reservoir is involved; however, "field" unlike "pool," may relate to two or more pools.

FLOWING WELL -- shall mean a well from which oil or gas flows naturally without pumping or other means of artificial lift.

GAS -- shall mean the natural gas obtained from gas or combination wells regardless of its chemical analysis.

GAS ALLOWABLE -- shall mean the amount of natural gas authorized to be produced by order of the Commission.

GAS ASSESSMENT -- shall mean the assessment on each thousand cubic feet of gas produced from a gas well to pay the costs incident to the administration of the rules of the Commission.

GAS REPRESSURING -- shall mean the introduction of gas or air into a common source of supply by artificial means in order to replenish, replace, or increase the gas energy causing the oil to flow out of the reservoir.

GAS-SOUR -- shall mean gas which contains hydrogen sulfide in sufficient quantities to render it unfit for domestic or commercial use.

GAS-WELL -- shall mean (1) a well which produces natural gas only; (2) any well capable of producing gas in commercial quantities and also producing oil from the same common source of supply but not in commercial quantities; or (3) any well classed as a gas well by the Commission for any reason; (4) a well that contains no liquid hydrocarbons in the reservoir.

GAS-LIFT -- shall mean a method of injecting gas for lifting a liquid from the well to the surface.

GAS-OIL RATIO -- shall mean the number of cubic feet of gas at atmospheric pressure, as produced from an oil well or combination well, divided by the number of barrels (42 gallons) of oil, the unit of time being a day of 24 hours.

ILLEGAL OIL -- shall mean oil which has been produced within the State of Arkansas from any well during any time that well has produced in excess of the amount allowed by any rule or order of

the Commission, as distinguished from oil produced within the State of Arkansas from a well not producing in excess of the amount so allowed, which is "legal oil."

ILLEGAL GAS -- shall mean gas which has been produced within the State of Arkansas from any well during any time that well has produced in excess of the amount allowed by any rule or order of the Commission, as distinguished from gas produced within the State of Arkansas from a well not producing in excess of the amount so allowed, which is "legal gas."

ILLEGAL PRODUCT -- shall mean any product of oil or gas, any part of which was processed or derived, in whole or in part, from illegal oil or illegal gas or from any product thereof as distinguished from "legal product," which is a product possessed or derived to no extent from illegal oil or illegal gas.

INDICES OF PRODUCTIVE VALUE -- shall mean the factors to be considered in ascertaining the productivity of all property in a common source of supply for the purpose of fixing the allowable production. These indices can mean, at the discretion of the Commission, acreage, gas oil ratios, static reservoir pressures, flowing pressures, fluid level drawdowns, the well or wells, or any other pertinent factors.

LEASE TANK -- shall mean the tank or other receptacle into which oil is produced either directly from a well or from a well through gas separator, gun barrel or similar equipment.

METER -- shall mean an instrument for measuring and recording the volume of gases or liquids.

MONTH and CALENDAR MONTH -- shall mean the period or interval of time from 7 a.m. on the first day of any month of the calendar to 7 a.m., of the first day of the next succeeding month of the calendar.

MUD-LADEN FLUID -- shall mean any approved mixture of water and clay or other material as the term is commonly used in the industry.

NATURAL GASOLINE -- shall mean gasoline manufactured from casinghead gas or from any natural gas.

OIL -- shall mean crude oil or petroleum.

OIL ALLOWABLE -- shall mean the amount of oil authorized to be produced by the order of the Commission.

OIL ASSESSMENT -- shall mean the assessment on each barrel of oil produced, from any field or reservoir, to pay the costs incident to the administration of the rules of the Commission.

OIL-PIPELINE -- shall mean oil free from water and basic sediment to the degree that it is acceptable for pipe line transportation and refinery use.

OIL-WELL -- shall mean any well capable of producing oil in paying quantities not a gas well.

OPERATOR -- shall mean any person who, duly authorized, is in charge of the development of a lease or the operation of a producing well.

OVERAGE, OVER-PRODUCTION -- shall mean the oil or gas produced in excess of the allowable as set by the Commission.

OWNER -- shall mean the person who was the right to drill into and produce from any field or reservoir, and to appropriate the production either for himself or for himself and another.

PERIOD, ALLOWABLE -- shall mean the month or day, as designated, in which allowable may be produced.

PERMEABILITY -- shall mean a measure, determined by scientific means, of the ability of fluid or gas to traverse the producing horizon in an oil or gas reservoir.

PERSON -- shall mean any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, Federal agency, or representative of any kind.

PETROLEUM -- shall mean the natural untreated oil obtained from an oil well.

PIPE LINE -- shall mean any pipes above or below the ground used or to be used for the transportation of oil or gas.

PIPE LINE OIL -- see, Oil, Pipeline.

PLUG -- shall mean the abandoning of a producing or non-productive well; the stopping of the flow of water, gas or oil in a well.

POOL -- shall mean an underground reservoir containing a common accumulation of crude petroleum oil or natural gas or both. Each zone of a general structure which is completely separated from any other zone in the structure is covered by the term "Pool" as used herein.

POROSITY -- shall mean the state or quality of being porous; the volume of pore space expressed as a percentage of the total volume of the rock mass; the percentage or pores of interspaces forming the total bulk of the material.

POTENTIAL -- shall mean the actual or properly computed daily ability of a well to produce oil or gas, either or both, as determined by the rules of the Commission.

PRESSURE BASE -- shall mean an absolute pressure agreed upon or set as a base for converting the volume of gas metered to correct volume. The standard pressure base shall be 14.65 pounds per square inch absolute.

PRESSURE MAINTENANCE -- **(1)** shall mean the reintroduction (in the early stages of field development) of gas or fluid produced from an oil, gas or combination well to maintain the pressure of the reservoir. **(2)** The introduction of gas or fluid for the same purpose but obtained from an outside source.

PRODUCER -- shall mean any person who owns, in whole or in part, a well capable of producing oil or gas or both in paying quantities.

PRODUCT -- means any commodity made from oil or gas, and shall include refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, casinghead gasoline, natural gas, gasoline, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixture of oil with one or more liquid products or by-products derived from oil or gas, whether herein above enumerated or not.

PRODUCTION, ILLEGAL, -- see Illegal Gas, Illegal Oil.

PRODUCTION INTERESTS -- shall mean the right to a specified part of production.

PROVEN OIL OR GAS LAND -- shall mean that area which has been shown by development and geological information to be such that additional wells drilled thereon are reasonably certain to be commercially productive of oil or gas or both.

PURCHASER -- shall mean any person who directly or indirectly purchases, transports, takes or otherwise removes production to his account from a well or lease. Purchaser is usually considered to be the person holding the Division Order.

RATABLE TAKE -- see Controlled Production.

RECOMPLETION -- shall mean completion operations performed in a source of supply that is separate and distinct from the source of supply in which the well was successfully completed prior to the commencement of the current completion operations.

REFINER -- shall mean every person who has any part in the control or management of any operation by which the physical or chemical characteristics of oil or products are changed, but exclusive of the operations of passing oil through separators to remove gas, placing oil in settling tanks to remove basic sediment and water, dehydrating oil, and generally cleaning and purifying oil.

REPRESSURE -- shall mean to increase the reservoir pressure by the introduction of gas or fluid into the reservoir.

RESERVOIR PRESSURE -- see Bottom Hole Pressure.

ROCK PRESSURE -- shall mean the well head pressure on a gas well that has been closed long enough to attain a maximum.

ROTARY DRILLING -- shall mean the hydraulic process of drilling, consisting of rotating a column of drill pipe to the bottom of which is attached a rotary drilling bit.

RUN -- shall mean oil or gas removed from the lease.

SEPARATOR -- shall mean an apparatus for separating gas from oil with relative efficiency, as it is produced.

SHUT-IN PRESSURE -- shall mean the pressure noted at the wellhead when the well is completely shut in. Not to be confused with Bottom Hole Pressure

SPUDDING -- shall mean the initial step in drilling.

STORER -- shall mean every person as herein defined who stores, terminals, retains in custody under warehouse or storage agreements or contracts, oil which comes to rest in his tank or other receptacle under control of said storer, but excluding the ordinary lease stock of producers.

TAKER -- see Purchaser.

TENDER -- shall mean a permit or certificate of clearance for the transportation of oil, gas, or products, approved and issued or registered under the authority of the Commission.

TENDERSHIP -- shall mean the production delivered from one person to another.

TOPPING PLANT -- shall mean a refinery designed to remove only the gasoline and kerosene fractions from oil.

TRAP PRESSURE -- shall mean pressure held at the oil and gas separator.

TRANSPORTER-- shall mean and include any common carrier by pipe line, barge, boat or other water conveyance, or truck or other conveyance except railroads, and any person transporting oil by pipeline, barge, boat or other water conveyance, or truck and other conveyance.

TUBING -- shall mean the conduit through which oil or gas is removed from a well.

VACUUM -- shall mean pressure which is reduced below the pressure of the atmosphere.

VOLATILE -- shall mean easily wasting away by evaporation.

WASTE -- in addition to its ordinary meaning, shall mean "physical waste" as that term is generally understood in the oil and gas industry. It shall include:

(1) The inefficient, excessive or improper use or dissipation of reservoir energy; and the locating, spacing, drilling, equipping, operating or producing of any oil or gas well or wells in a manner which results, or tends to result, in reducing the quantity of oil or gas ultimately to be recovered from any pool in this state.

(2) The inefficient storing of oil; and the locating, spacing, drilling, equipping, operating or producing of any oil or gas well or wells in a manner causing, or tending to cause, unnecessary or excessive surface loss or destruction of oil or gas.

(3) Abuse of the correlative rights and opportunities of each owner of oil and gas in a common reservoir due to non-uniform, disproportionate, and unratable withdrawals causing undue drainage between tracts of land.

(4) Producing oil or gas in such manner as to cause unnecessary water channeling or coning.

(5) The operation of any oil well or wells with an inefficient gas-oil ratio.

(6) The drowning with water of any stratum or part thereof capable of producing oil or gas.

(7) Underground waste however caused and whether or not defined.

(8) The creation of unnecessary fire hazards.

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

(10) The use of gas for the manufacture of carbon black.

(11) Permitting gas produced from a gas well to escape into the air.

WATER CONE -- shall mean the creation of irregularly intruding water by allowing a well to produce too rapidly.

WELL LOG -- shall mean an electrical, or any other type of survey, made for the purpose of ascertaining the strata through which a well bore has penetrated.

WILDCAT WELL -- shall mean a well drilled outside the geological confines of proven production.

WORKOVER -- shall mean work of a remedial nature performed within the vertical confines of the same source of supply.

(Source: 1992 rule book)

RULE A-5: ENFORCEMENT PROCEDURES

a) Definitions:

1) "Commission" shall mean the Arkansas Oil and Gas Commission, on which the Director serves as secretary, but is a non-voting member.

2) "Director" shall mean the Commission Director of Production and Conservation.

3) "Regulated Entity" shall mean all operators, owners, producers or persons subject to Commission regulatory authority.

4) "UIC" shall mean the Underground Injection Control program of the Federal Safe Drinking Water Act.

b) Any regulated entity engaged in the drilling, operation or plugging of any production, injection, or other well or drill hole regulated by the Commission; or the operation of any crude oil or gas production or injection facility; or the operation of any natural gas line or crude oil flowline regulated by the Commission; or transporter by tank truck of any oilfield production or completion fluid; or seismic activity; or any other activity regulated by the Commission, is subject to this rule for violation of any oil, gas and/or brine statutes, or any rule or permit condition of the Commission.

c) In accordance with Ark. Code Ann. § 15-72-103(c) or § 15-76-303(c), any person knowingly and willfully aiding or abetting any other person in the violation of any statute relating to the conservation of oil, gas and/or brine, or the violation of any provision of the state oil, gas and/or brine statutes, or any rule, order, or permit condition, shall be subject to the same penalties as are prescribed herein for the regulated entity.

d) Notice of Non-Compliance

1) A Notice of Non-Compliance may be issued when any regulated entity is in non-compliance with any requirement of the Arkansas oil, gas and/or brine statutes, or rules, orders, or any permit condition, and:

A) That the non-compliance was not caused by the regulated entity's deliberate action;

B) That any action necessary to abate the non-compliance was commenced immediately and was or will be completed within a specified date certain, as established by the Director, or his or her designee, not to exceed thirty (30) days from the date of the determination that the regulated entity was determined to be in non-compliance; and

C) That the non-compliance has not caused and cannot reasonably be expected to cause significant environmental harm or damage to property.

2) The notice of non-compliance shall be documented in writing and, delivered via first class mail to the regulated entity or to the regulated entity's representative as reported on the AOGC Form 1 Organization Report. The written notification shall indicate the nature and circumstances of the non-compliance, and the time within which and the means by which the non-compliance is to be abated.

3) If abatement was not completed as specified in the written notification, the Director, or his or her designee, may issue a formal Notice of Violation in accordance with subparagraph (e) below.

4) The provisions of this subparagraph (d), shall not apply to the following types of incidents, which may require a Notice of Violation to be issued in accordance with subparagraph (e) below:

A) Conducting any regulated activity specified in paragraph (b) above prior to issuance or re-issuance of the appropriate Commission permit or authority;

B) Operating an annular or casing injection/disposal well or a well with pressure on the annulus;

C) Failure to maintain required performance bond or pay annual well fees;

D) Failure to establish mechanical integrity on any UIC well prior to operation, or failure to repair any UIC well following failure of mechanical integrity;

E) Commencing any work or activity on a well or its related production facility or well site that has been placed in the Abandoned and Orphan Well Plugging Program;

F) Failure to provide emergency response for a crude oil or saltwater spill;

G) Improper discharge or disposal of produced fluids; or

H) Operating a well in violation of spacing requirements or permit conditions.

e) Notice of Violation(s)

1) A Notice of Violation may be issued, by the Director or his or her designee, when any regulated entity is in violation of any requirements of the Arkansas oil, gas, and/or brine statutes, or rules, orders, or any permit conditions of the Commission. Unless otherwise determined by the Commission after notice and a hearing, a regulated entity shall not be held responsible by the Commission for violations of oil, gas and/or brine statutes, or rules, or permit conditions of the Commission in the absence of the issuance of an underlying Notice of Violation.

2) The Notice of Violation shall be in writing and contain:

A) A statement regarding the nature of the violation, including a citation to the specific section of the oil, gas and/or brine statutes, or any rule, order or permit condition of the Commission alleged to have been violated;

B) The suggested action needed to abate the violation including any appropriate remedial measures to prevent future violations;

C) The time within which the violation should be abated; and

D) A notice of any civil penalties, as specified in subparagraph g) below, the Director will request to be issued by the Commission.

E) A notice of any civil penalties for violations of natural gas line regulations under United States Department of Transportation, Office of Pipeline Safety jurisdiction in accordance with appropriate federal regulation specified in 49 CFR 190.223, the Director will request to be issued by the Commission.

3) The Notice of Violation may include a well, lease, or unit cessation requirement for the following types of violations:

A) Violation of production allowable;

B) Failure to maintain required well specific performance bond;

C) Drilling or operating, without a Commission permit or permit transfer, a well required to be permitted or transferred;

D) Operating a well that has been determined to be abandoned by the Commission;

E) Failure to plug a leaking well or a well ordered to be plugged by the Commission;

F) Operating an annular or casing injection/disposal well;

G) Operating a UIC Class II or V well with a failed mechanical integrity test;

H) Operating a UIC Class II or V well with pressure on the annulus indicating tubing and/or casing failure;

I) Failure to provide emergency response or remediate a crude oil or produced water spill;

J) Improper disposal or discharge of produced fluids; or

K) Any other violation for which a cessation requirement is authorized by an oil, gas and/or brine statute, or rule, order or permit condition.

4) The Notice of Violation may also include a state-wide cessation requirement for the following types of violations:

A) Failure to maintain required blanket financial assurance as specified in General Rule B-2;

B) Failure to pay annual well fees as specified in General Rule B-2;

C) Failure to pay any monies due the Abandoned and Orphaned Well Plugging Fund as specified in General Rule G-1; or

D) Failure to comply with the provisions of General Rule B-42, or General Rule E-3.

E) Any other violation for which a state-wide cessation requirement is authorized by an oil, gas and/or brine statute, or rule, order or permit condition.

5) The Director, or his or her designee, shall send via certified mail the Notice of Violation to the regulated entity, or the regulated entity's representative as reported on the AOGC Form 1 Organization Report, charged with the violation(s), or provide personal delivery of a copy of the notice to the regulated entity, or the regulated entity's representative.

6) The regulated entity charged with the violation(s) may request a Director's Review of the Notice of Violation and provide the Director, in writing, any information in mitigation of the violation(s) on or before thirty (30) calendar days of the mailing or personal delivery of the original Notice of Violation, unless a shorter time period is specified in the Notice of Violation for instances where there is a condition that creates an imminent danger to the health or safety of the public or threatens significant environmental harm or damage to the property. Such written information may include a proposed alternative to the required action needed to abate the violation(s). Upon receipt of such information from the regulated entity, the Director, shall conduct a review.

7) During the review, the Director may consider any of the following criteria in reaching a Final Director's Decision regarding the violation(s):

   A) The regulated entity's history of previous violations, including violations at other locations and under other permits;

   B) The seriousness of the violation, including any irreparable harm to the environment or damage to property;

   C) The degree of culpability of the regulated entity; and

   D) The existence of any additional conditions or factors in aggravation or mitigation of the violation, including information provided by the regulated entity.

8) Upon completion of the review, the Director shall issue a Final Director's Decision to:

   A) affirm the violation; or

   B) vacate the violation; or

   C) amend or modify the type of violation and abatement requirements specified in the violation; or

   D) establish probationary or permanent modification or conditions to any underlying permit related to the violation, which may include special monitoring or reporting requirements; or

   E) enter into a settlement agreement to extend the amount of time provided to complete remedial actions necessary to abate the violations or reduce the amount of the requested assessed civil penalty.

9) The Final Director's Decision shall be delivered to the regulated entity, or the regulated entity's representative, as reported on the AOGC Form 1 Organization Report, via first class mail. The Final Director's Decision may be appealed to the Commission by filing an application in accordance with General Rule A-2, A-3, and other applicable hearing procedures. The application to appeal the Final Director's Decision is required to be received by the Director within thirty (30) days of the mailing of the Final Director's Decision. The application shall state the reason for the appeal and shall be scheduled to

be heard by the Commission in accordance with General Rule A-2, A-3, and other applicable hearing procedures.

10) A Notice of Violation for which a Director's Review has not been requested, shall become a final administrative decision of the Commission thirty (30) days following the mailing of the Notice of Violation.

11) A Final Director's Decision not appealed to the Commission within thirty (30) days of mailing of the Final Director's Decision shall become a final administrative decision of the Commission.

12) All violations specified in a Notice of Violation(s) which have become a final administrative decision in accordance with subparagraph e) 10), a Final Director's Decision which has become a final administrative decision of the Commission in accordance with subparagraph e) 11), or by Order of the Commission, shall be fully abated within the time frame specified in the original Notice of Violation, Final Director's Decision, or Order of the Commission. No further permits or authorities shall be issued to the regulated entity until all outstanding violations specified in a Notice of Violation which has become a final administrative decision in accordance with subparagraph e) 10), a Final Director's Decision which has become a final administrative decision of the Commission in accordance with subparagraph e) 11), or by Order of the Commission have been fully abated.

f) In addition to the issuance of a Notice of Violation(s), the Director may initiate further enforcement proceedings, as provided for in statute, as follows:

1) Assessment of a civil penalty as provided in Ark. Code Ann. § 15-71-114, § 15-72-103, § 15-72-202, or § 15-76-303;

2) The revocation of a certificate of clearance on a state-wide basis, as provided for in Ark. Code Ann. § 15-71-110 (11);

3) The filing of a civil complaint in a court of competent jurisdiction in the County where the violation occurred, as provided for in Ark. Code Ann. § 15-72-108 or § 15-76-304;

4) The filing of a criminal complaint in any court of competent jurisdiction, as provided for in Ark. Code Ann. § 15-71-114, § 15-72-104 or § 15-76-303.

g) Civil Penalties

1) The Director shall determine whether to request the assessment of civil penalties based on failure to comply with the applicable abatement requirements for violations issued under subparagraphs (g) (2) and (3) below. The Director shall determine whether to request the assessment of civil penalties for violations issued under subparagraphs (g) (4) and (5) below. If a civil penalty is requested by the Director, the Regulated Entity may voluntarily agree to the assessment and pay the civil penalty as requested or modified by the Director, or the Director or his designee may file an application, in accordance with General Rule A-2, A-3, and other applicable hearing procedures, to request the issuance of the requested civil penalty by the Commission. The maximum amount of the Director's requested civil penalty shall be computed as provided in subparagraphs (g) (2) through (5) below. However, the Commission is not bound by the Director's request, or the amounts provided below, and may impose civil penalties of up to the maximum amounts permitted by law.

2) Administrative violations, defined as failure to file required reports and forms and to provide required notices (excluding spill notice), including, but not limited to regulated activities such as, the failure to file production and well reports or other reports required by Commission rules, orders or permit conditions; failure to notify the Commission before the setting of surface casing, or the plugging of a well; failure to maintain required performance bond in force for the wells under permit; or pay annual well fees within the specified time. The Director may request the assessment of up to $1000 per administrative violation and up to $1000 per day for each day the violation remains unabated after the specified compliance date. The per administrative violation civil penalty request shall be calculated as follows:

A) No previous violation of the same rule: $250. One previous violations of the same rule: $500. Two or more previous violations of the same rule: $1000. The fourth and each subsequent violation of the same rule shall be considered a significant violation in accordance with subparagraph g) 4) below.

B) The time frame used for determining previous violations shall be limited to the regulated entity's violation record for the preceding three full calendar years before the issuance of the violation.

3) Operating violations, defined as failure to maintain compliance with Commission rules on well drilling and operation, and production facility, pipeline and seismic operations and/or commencing operations requiring a permit prior to issuance or re-issuance of the required permit or authority. These operations include, but are not limited to regulated activities such as, operating a well or natural gas pipeline system without the proper permit or transfer of ownership, failure to maintain a well or crude oil flow line in a leak-free condition, failure to comply with non-jurisdictional natural gas pipeline requirements, failure to notify of a spill occurrence, failure to maintain containment dikes, or operating an Exploration and Production Fluid Transportation System without a proper permit. Multiple incidents of the same violation against a regulated entity on the same occasion shall not be considered separate violations. The Director may request the assessment of up to $2500 per operating violation and up to $2500 per day for each day the violation remains unabated after the specified compliance date, with the exception that operating violations as specified in Ark. Code Ann. § 15-76-303 are limited to a maximum of $1,000 per operating violation. The per operating violation civil penalty shall be calculated as follows:

A) No previous violation of the same rule $500. One previous violation of the same rule, $750; two or more previous violations of the same rule, $1000. The fourth and each subsequent violation of the same rule shall be considered a significant violation in accordance with subparagraph g) 4) below.

B) The time frame used for determining previous violations shall be limited to the regulated entity's violation record for the preceding three full calendar years before the issuance of the violation; plus

C) If the violation had a low degree of probability to cause environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $250; or, if the violation had a high degree of probability to cause environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $500; or, if the

violation caused environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $1000, or

D) If the violation created a hazard to the safety of any person, such as the contamination of a potable water well or emission of hydrogen sulfide gas, add $2000.

4) Except as limited in Ark. Code Ann. § 15-76-303, or as otherwise provided in subparagraphs g) 5) or 6) below, significant violations may result in a request by the Director or his or her designee, of a civil penalty of up to $2500 per violation and up to $2500 per day for each day of the violation for the following types of violations: failure to comply with the provisions of General Rule A-7, failure to comply with well spacing provisions, operating a UIC well without a proper permit, operating an annular or casing injection/disposal well, operating a UIC well prior to establishing mechanical integrity, operating a UIC well with a failed mechanical integrity test, operating a UIC well with pressure on the annulus, failure to provide emergency response or remediate a crude oil or produced water spill, or the improper disposal or discharge of produced fluids. The per violation civil penalty shall be computed as follows:

A) An initial amount of $1000; plus

B) One or more previous violations of the same type: add $500 per violation; plus

C) If the violation caused environmental impact to surface water, ground water or wildlife: add $1000, or if the violation created a hazard to the safety of any person, such as the contamination of a potable water well or emission of hydrogen sulfide gas: add $1500.

D) The time frame used for determining previous violations shall be limited to the regulated entity's violation record for the preceding three full calendar years before the issuance of the violation.

5) In accordance with Ark. Code Ann. §15-72-103, the Director, or his or her designee, may request a civil penalty of up to $100,000 for any person who transports a liquid or other substance and violates a rule or order of the commission by dumping or disposing of the liquid or other substance improperly or without authorization at a well or well site.

6) The Director, or his or her designee, may request any amount in civil penalties authorized by applicable federal law for violations of the United States Department of Transportation, Office of Pipeline Safety jurisdictional natural gas line requirements.

h) All civil penalties assessed and paid to the Commission shall be deposited in the Commission operating fund. Additionally, all civil penalties assessed and paid, for violations specified in Ark. Code Ann. § 15-72-202 shall be turned into the general fund of the county where the violation occurred to be used on roads, bridges, and highways at the discretion of the county court.

(Source: new rule September 14, 2008; amended July 17, 2009; amended October 24, 2009; amended July 29, 2011; amended February 17, 2012; amended January 20, 2014)

RULE A-6: RESERVED

Reserved for Future Use

RULE A-7: DETERMINATION OF NATURAL GAS WELL CATEGORIES FOR SEVERANCE TAX PURPOSES

a) Applicability

In accordance with Ark. Code Ann. § 26-58-128, the Director of the Oil and Gas Commission shall determine the well categories for all gas production wells, which will be used by the Arkansas Department of Finance and Administration to determine the appropriate severance tax rate for each well. All gas production wells under the jurisdiction of the Oil and Gas Commission are subject to the provisions of this rule.

b) Definitions:

1) "Commission" shall mean the Arkansas Oil and Gas Commission, on which the Director serves as secretary, but is a non-voting member.

2) "Conventional Gas Well" means a gas well that is not classified as a high cost gas well.

3) "Director" means the Oil and Gas Commission Director of Production and Conservation.

4) "High Cost Gas Well" means a gas well that:

A) Produces gas from any shale formation, including but not limited to the Fayetteville Shale, Woodford Shale, Moorefield Shale and the Chattanooga Shale, or their stratigraphic equivalents as described in published stratigraphic nomenclature recognized by the Arkansas Geologic Survey; or

B) Produces gas from any completion that is located at a depth of more than 12,500 feet below the surface of the earth, where the term "depth" means the length of the maximum continuous drilling string of drill pipe used between the drill bit face and the drilling rig's Kelly bushing; or

C) Produces gas from a tight gas formation which is defined as a formation which:

i) Has previously been determined to be a low permeability formation by Commission Orders or field rules for Booneville and Chismville (84-2003-07), Gragg (89-2004-07), Waveland (86-2004-07), Rich Mountain (304-2006-09), Mansfield (28-2003-03), Witcherville and Excelsior (103-2005-07); and General Rule B-44; or

ii) Is determined by the Director to have an estimated in situ permeability of one-tenth millidarcy (0.1 mD) or less; or

iii) Is determined to be a tight gas formation by field rule, general rule or orders approved by the Commission and issued by the Director.

D) Produces gas from a geopressured brine; or

E) Produces occluded gas from a coal seam.

5) "Marginal Conventional Gas Well" shall mean a conventional gas well which is incapable of producing more than 250 Mcf per day, from all zones producing in such well, as determined by the sum of the individual deliverability rates for each zone, using one of the current wellhead deliverability rate methodologies described in subparagraph h) below.

6) "Marginal High Cost Gas Well" shall mean a high cost gas well which is incapable of producing more than 100 Mcf per day, from all zones producing in such well, as determined by the sum of the individual deliverability rates for each zone, using one of the current wellhead deliverability rate methodologies described in subparagraph h) below.

7) "New Discovery Gas Well" shall mean any conventional gas well for the period commencing on the date of first production and ending on the date that is 24 consecutive calendar months following the date of first production.

c) On or before January 1, 2009, the Director shall determine the initial well category for each existing gas producing well in the State. If a well contains two or more separately metered producing zones (sources of supply), and one or more of the producing zones are different categories, the well category shall be based on which zone in the well produces the larger percentage of the total well production, based on the most recent back pressure test methodology specified in General Rule D-16. On or before January 1, 2009 the Director shall notify each permit holder of each existing wells determination as a:

1) High Cost Gas Well, including whether it is a high cost gas well producing gas from the date of first production and for a minimum period of 36 consecutive calendar months following the date of first production, unless a longer time period is granted by the Department of Finance and Administration in accordance with Ark Code Ann. § 26-58-127; or

2) Marginal Conventional Gas Well; or

3) Marginal High Cost Gas Well; or

4) New Discovery Gas Well; or

5) A Conventional Gas Well.

d) After January 1, 2009 the Director shall determine, at the time of permitting each new well, the appropriate well category as specified in subparagraph c) above, which shall be effective the date of first production from the well. This well category determination, made at the time of the initial new well permit issuance or as amended in accordance with this subparagraph or subparagraph g) below, shall determine the well category throughout the life of that well. Once a permit is issued, if a well is completed in two or more separately metered producing zones (sources of supply), and one or more of the producing zones are different categories, with respect to a Conventional Gas Well or a High Cost Gas Well, the well category shall be based on which zone in the well produces the larger percentage of the total well production, based on the initial back pressure tests required by General Rule D-16. The well category determination, shall determine the category for that well throughout the life of that well, regardless if other zones are produced within the well at a later date, until such time as the well qualifies as a Marginal Conventional Gas Well or a Marginal High Cost Gas Well.

e) Following the well category determination for all existing wells on January 1, 2009, and the ongoing categorization for all new wells after January 1, 2009, the permit holder may request at any time, on a form prescribed by the Director, another well category determination with respect to the well category definitions specified in subparagraph b) above, in accordance with the application procedures specified in subparagraph i) below.

f) Upon submission of the application and supporting documentation or other required information, the Director shall make a determination within fifteen (15) calendar days from the receipt of such application.

1) The effective date of the well category determination request shall automatically be the first day of the next month following the postmark date the application was mailed to the Director or date of the Director's Office date stamp, if delivered in person to the Director.

2) If approved by the Director, the application shall be sent via first class mail to the permit holder and a copy forwarded to the Department of Finance and Administration ("DFA").

3) If the application is denied by the Director, the permit holder may appeal the Director's determination to the Commission by filing an application in accordance with General Rule A-2, A-3, and other applicable hearing procedures. If the permit holder does not appeal the denial, and the date of the Director's denial occurs after the effective date of the well determination request as defined in subparagraph f) 1) above, the permit holder may be subject to additional payment provisions in accordance with DFA procedures. If the permit holder appeals the denial, the effective date of the well categorization request shall remain in effect pending the outcome of the appeal.

g) If following a review of completion reports, monthly production reports, the applicable wellhead deliverability rate, utilizing one of the current methodologies specified in subparagraph h) below, or other information, the Director determines a well is not correctly categorized, the Director shall determine the correct well category and notify the permit holder. The corrected well category determination shall become effective on the first day of the month following the month in which the Director notifies the permit holder of the corrected well category determination, unless the permit holder files an appeal of the Director's decision in accordance with General Rule A-2, A-3, and other applicable hearing procedures.

h) All existing well category determinations under subparagraph c) and all new well category determinations under subparagraph d) shall be made on the basis of one of the following current wellhead deliverability rate methodologies:

1) Establishing cumulative deliverability of the well utilizing test methodologies specified in General Rule D-16; or

2) Calculating the cumulative deliverability of the well utilizing the most recent six month average daily rate of production for the well under actual operating conditions by dividing the total gas reported for the well by the number of days the well produced during the applicable six month period. However, this well category determination method is not applicable for wells subject to an exceptional location penalty.

i) Well Category Determination and Application Procedures

1) High Cost Gas Well.

A) The High Cost Gas Well category shall be assigned to all existing wells on January 1, 2009, which satisfy the definition of a High Cost Gas Well in accordance with subparagraph b) 4) above. If on that date the High Cost Gas Well has a reported date of first production on or after January 1, 2006, the well shall automatically qualify for a cost recovery period for a period of 36 consecutive calendar months following the date of first production, unless a longer time period is granted by the Department of Finance and Administration in accordance with Ark Code Ann. § 26-58-127.

B) On or after January 1, 2009, the High Cost Gas Well category shall be assigned to all newly permitted wells that satisfy the definition of a High Cost Gas Well in accordance with subparagraph b) 4) above at the time of well categorization in accordance with subparagraphs d) and g) above. The well shall automatically qualify for a cost recovery period for a period of 36 consecutive calendar months following the date of first production, unless a longer time period is granted by the Department of Finance and Administration in accordance with Ark Code Ann. § 26-58-127.

C) At the conclusion of the cost recovery period, specified in subparagraph i) 1) A) and B) above, the well shall automatically be re-classified as a High Cost Gas Well no longer subject to the tax rate for the cost recovery period, and shall be subject to the applicable severance tax rate specified in Ark Code Ann. § 26-58-111(5)(D) unless an application is made for classification as a Marginal High Cost Gas Well in accordance with subparagraph i) 3) B) below. The effective date of the automatic re-classification shall be the first day of the month following the month in which the specified recovery period expired.

2) New Discovery Gas Well

A) The New Discovery Gas Well category shall be assigned to all existing conventional wells on January 1, 2009, which as of that date, have a reported date of first production on or after January 1, 2007.

B) The New Discovery Gas Well category shall be automatically assigned to all newly permitted conventional wells on or after January 1, 2009 at the time of well categorization in accordance with subparagraphs d) and g) above. The well category determination shall remain in effect for 24 consecutive calendar months following the date of first production.

C) At the conclusion of the 24 consecutive calendar months following the date of first production, the New Discovery Gas Well determination shall automatically terminate. The effective date of the automatic termination shall be the first day of the month following the month in which the actual date of termination occurred. The well shall be automatically re-classified as a Conventional Gas Well subject to the applicable severance tax rate specified in Ark Code Ann. § 26-58-111(5)(D), unless application is made for classification as a Marginal Conventional Gas Well in accordance with subparagraph i) 3) B) below.

3) Marginal Conventional Gas Well and Marginal High Cost Gas Well

A) The applicable Marginal Gas well category shall be assigned to all existing Conventional Gas Wells and High Cost Gas Wells on January 1, 2009, that qualify as either a Marginal Conventional Gas Well or a Marginal High Cost Gas

Well and, which as of that date do not qualify as either a New Discovery Gas Well during the cost recovery period set forth in subparagraphs i) 2) A), and B) above, or a High Cost Gas Well during the cost recovery period set forth in subparagraphs i) 1) A) and B) above.

B) When a Conventional Gas Well qualifies as a Marginal Conventional Gas Well, or a High Cost Gas Well qualifies as a Marginal High Cost Gas Well, a permit holder may apply to the Director, for a Marginal Conventional Gas Well or Marginal High Cost Gas Well category determination. The request shall be on a form prescribed by the Director and shall include a copy of the most recent well head deliverability rate determination for all producing zones based on one of the current wellhead deliverability rate methodologies specified in subparagraph h) above.

C) The effective date of the applicable Marginal Gas well determination shall be the first day of the month following the month in which the permit holder's application was received in accordance with subparagraph f) above.

D) A permit holder shall immediately notify the Director in writing when a well, which has been previously determined to be a Marginal Conventional Gas Well no longer qualifies as a Marginal Conventional Gas Well, or a Marginal High Cost Gas Well no longer qualifies as a Marginal High Cost Gas Well. When a previously determined Marginal Conventional Gas Well becomes capable of producing more than 250 Mcf per day over a 30 day period or a well previously determined to be a Marginal High Cost Gas Well becomes capable of producing more than 100 Mcf per day over a 30 day period, the permit holder shall submit a copy of the most recent well-head deliverability rates for each producing zone in the well, based on one of the current wellhead deliverability rate methodologies specified in subparagraph h) above, along with the required written notice to the Director.

4) Wells not classified as a High Cost Gas Well, New Discovery Gas Well, Marginal Conventional Gas Well or Marginal High Cost Gas Well, as described above, shall be automatically classified as a Conventional Gas Well subject to the severance tax rate specified in Ark Code Ann. § 26-58-111(5)(D).

j) Failure to comply with any provision of this rule may result in the initiation of enforcement actions in accordance with General Rule A-5, including the assessment of a civil penalty not to exceed two thousand five hundred dollars ($2500) per day for each day of the violation.

(Source: new rule November 16, 2008; amended June 5, 2009)

RULE A-8: REPEALED

Rule Repealed Effective July 1, 2016

GENERAL RULE B - DRILLING AND PRODUCTION

RULE B-1: APPLICATION TO DRILL A PRODUCTION WELL

a) Definitions:

1) "Production Well" means a well drilled, deepened, or re-entered after plugging, for the exploration or production of oil and/or gas or brine; or a well drilled, deepened or re-entered after plugging for a water supply for use in connection with an enhanced oil recovery project.

2) "Deepen" for a cased well means an operation whereby a well is drilled to a measured depth below the cement casing shoe. For an open hole completion, "Deepen" means an operation whereby a well is drilled below the original measured depth of the well.

3) "Drill" means the commencement of an operation to either set conductor pipe or the moving in a drilling rig capable of drilling to a depth to set the requisite amount of surface casing and spudding the well, if conductor pipe is not used.

4) "Permit Holder" means the person to whom the permit is issued and is responsible for all regulatory requirements relative to the production well.

5) "Re-enter" means an operation whereby access to a previously plugged wellbore is re-established for any purpose including replugging.

6) "Shale Operations" means drilling activities relating to the production of gas and other petroleum hydrocarbons directed at an unconventional shale gas formation in a county listed in Arkansas General Rule B-43(c) or (d). "Shale Operations" does not include: (i) the periodic inspection, maintenance, or repair of completion activities; (ii) preparatory activities such as inspection, surveying, or staking; or (iii) drilling additional wells, redrilling, or recompletion operations on an existing drilling pad if the operator does not expand the existing pad. For purposes of this rule, "Shale Operations" does include well site construction operations.

7) "Spud" means the commencement of drilling a wellbore to a depth to set the requisite amount of surface casing.

b) Permit Application Procedures for a Permit to Drill, Deepen or Re-enter a Production Well

1) No person shall drill, deepen, or re-enter a plugged production well, without a permit. A copy of the permit shall be posted on site prior to a well being spud or the commencement of deepening or re-entering operations.

2) The Permit Holder is required to provide notice to the surface owner in accordance with Ark Code Ann. § 15-72-203.

A) If notice is required in accordance with Ark Code Ann § 15-72-203 (c) and entry upon the surface owner's surface estate is required on or after the effective date of this rule, the notice shall contain:

A) the proposed date Shale Operations will commence; and

B) the location of the proposed well and the pad location, including the section, township, range, and plat of the pad location, if available; and

C) a statement that the Permit Holder has a pending or approved drilling permit for the proposed Shale Operations on the surface owner's property and that the permit shall be available for inspection by the surface owner on request by the surface owner; and

D) the name, address, telephone number, fax number, and electronic mailing address of the Permit Holder or the Permit Holder's agent.

B) The Notice shall be sent by certified United States mail or delivered personally, to the surface owner at the address of the surface owner stated in the public records of the county collector of the county in which the surface owner's property is located, at least fourteen (14) days before the Permit Holder proposes to begin Shale Operations on the surface owner's property.

C) After written notice of the Permit Holder's intent to begin Shale Operations is given under this subsection, a Permit Holder is not required to give any other notice to begin, conduct, or complete Shale Operations on the surface owner's property.

D) Written notice under this subsection is:

i) presumed delivered three (3) days after mailing by certified mail;

ii) effective immediately upon hand delivery;

E) Written notice is not required:

i) for emergency situations in which the Shale Operations are required to protect the public health and safety or the environment; or

ii) if a surface owner has a contractual relationship with a Permit Holder or the Permit Holder's agent that specifies when or how the Permit Holder shall give notice regarding the beginning of Shale Operations.

F) After receipt of a written notice of the Permit Holder's intent to begin Shale Operations under this subsection, the surface owner shall not make alterations to a proposed drilling location to interfere with the Shale Operations for which the surface owner received the notice.

G) The provisions of subparagraphs b) 2) A) through F) above do not supersede, modify, or supplant the notice provisions of General Rule B-42.

3) The Permit Holder shall notify the appropriate Commission Regional Office by telephone, or other approved method, a minimum of twenty-four (24) hours prior to a well being spud or the commencement of deepening or re-entering operations. Commission staff may conduct site inspections as deemed necessary.

4) No production well may be drilled at a surface location other than that specified on the permit, except that if a Permit Holder has commenced drilling operations and the production well is lost due to adverse drilling conditions prior to surface casing being set, the Permit Holder may request an amendment of the permit without a fee for the new location, provided the production well remains on the same surface owners' property where the production well was originally permitted. The Director may approve the commencement of drilling operations prior to the filing of an amended permit. Movement of the production well_location off the original surface owners' property, or after surface casing has been set, requires the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

5) Application for a permit to drill, deepen or re-enter a plugged production well shall be made on forms prescribed by the Director. The application shall be executed under penalties of perjury, accompanied by a non-refundable permit fee of $300.00; and the permit shall not be issued until any required financial assurance in accordance with General Rule B-2 is submitted and approved.

6) If the application does not contain all of the required information or required documents, the Director, or his designee, shall notify the applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application, and shall advise the applicant that the application will be deemed denied unless the information or documents are received within sixty (60) days following the date of mailing or personal delivery of the notification.

7) Permits shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged production well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed 1 year from the date of commencement of the drilling, deepening or re-entry of plugged production well operations authorized by the permit, at which time the production well shall be plugged or a new permit application, along with a new permit fee and plat, must be filed.

8) Permits for the drilling, deepening or re-entry of plugged production well are not transferable prior to the completion of drilling operations and the setting of surface casing. A new permit application, along with a new permit fee and plat must be filed.

9) The permit application to drill, deepen or re-enter a plugged production well shall include at a minimum:

   A) The proposed name of the production well.

   B) The surveyed location and ground elevation of the production well. A survey is not required for a deepened production well, or a re-entered plugged production well, if the original production well location was surveyed and shown on the original production well permit application. If the application is for a horizontal production well, the surface location and proposed bottom hole location of the lateral portion of the horizontal production well shall be shown. If applicable, a Form 25 must be submitted for horizontal production wells where the costs and production are to be shared between drilling units in accordance with General Rule B-43 or B-44, or a Form 5 must be submitted for a location exception in accordance with General Rule B-40.

C) A plat showing:

i) The exact location of the production well proposed to be drilled, deepened or re-entered; an outline of the proposed drilling unit and/or leasehold, whichever is applicable, unless the production well is a wildcat well; and the distance from the production well to the nearest section lines, drilling unit lines and or lease lines, whichever is applicable; and

ii) If the production well is located within a controlled oil or gas field, the plat shall also include the location of all producing wells completed or producing within the same common source of supply in the drilling unit and/or leasehold.

D) The name of the proposed drilling contractor.

E) The proposed depth of the production well, and the name of the deepest geologic formation to be tested.

10) The application for a permit to drill, deepen or re-enter a plugged production well shall be signed by a person authorized to sign for such owner as specified on the Organizational Report filed in accordance with General Rule B-13.

11) The applicant must be authorized to do business in the State or Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission.

12) If the applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, and in no circumstances be unduly withheld, unless:

A) The applicant has falsified or otherwise misstated any material information on or relative to the permit application;

B) No further permits or authorities may be issued in accordance with General Rule A-5.

c) Production Well Drilling Permit Revocation Procedures

1) The Director may revoke a production well drilling permit if the Permit Holder fails to meet permit conditions as specified in the production well drilling permit, the production well permit was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the production well drilling permit in writing. Following the revocation notice the Permit Holder is required to plug the production well. The Permit holder shall have thirty (30) days from the date of the production well drilling permit to appeal the Director's Decision to revoke the production well drilling permit in accordance with General Rule A-2, A-3, and other applicable hearing procedures. Drilling or production may not commence or continue during the appeal process. A revocation of a production well drilling permit for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

(Source: 1992 rule book; amended July 29, 2011; amended January 20, 2014)

RULE B-2: PROOF OF FINANCIAL RESPONSIBILITY REQUIRED TO BE FURNISHED

a. For purposes of this rule, the person, operator, producer, or owner designated by the Director of Production and Conservation or his designee as the party responsible for compliance, and whom is the entity required to hold the permit to drill, produce, dispose or inject will be referred to as the permit holder.

b. Financial Assurance is required to be submitted with the following applications:

1. An application to drill an oil and/or gas well, Class II disposal well, injection well, brine production well, Class V brine disposal well, water supply well or other type of exploratory hole(s) or well(s); or

2. An application to transfer ownership or operations of any existing oil and/or gas well, Class II disposal well, injection well, brine production well, Class V brine disposal well, water supply well or other type of exploratory hole(s) or well(s) to another permit holder.

c. Financial Assurance is required to remain in full force and effect by the designated permit holder:

1. for one year after the issuance of the permit to drill in accordance with A.C.A. 15-72-214; or

2. until the well(s) have been plugged and associated production site(s) restored in accordance with Commission rules; or

3. the well(s) have been transferred to a new permit holder in accordance with Commission rules; or

4. all outstanding notices of violation or orders of compliance issued against the permit holder have been satisfied; or

5. the permit holder has paid annual fee assessments to the Commission in accordance with section h. of this rule for two consecutive years, and such permit holder is not in violation of the Commission's rules or statutes; or

6. all permit holders of record with the Commission on January 1, 2006 who were assessed annual fees in accordance with section (h) of this rule and paid such fees, and who were not in violation of any Commission order or rule at the time the fees were paid.

d. Financial Assurance shall be submitted and payable to the Commission in the form of:

1. A surety bond issued by a surety company authorized to transact business in Arkansas; or

2. An irrevocable letter of credit subject to the following conditions:

A. The letter of credit shall be issued by a bank whose deposits are insured by the Federal Deposit Insurance Corporation.

B. The letter of credit shall provide on its face that the Commission, its lawful assigns, or the attorneys for the Commission or its assigns, may sue, waive notice and process, appear on behalf of, and confess judgment against the issuing bank (and any confirming bank) in the event that the letter of credit is dishonored. The

letter of credit shall be deemed to be made in Union County, Arkansas for the purpose of enforcement and any actions thereon shall be enforceable in the Courts of Arkansas, and shall be construed under Arkansas law.

3. A Certificate of Deposit subject to the following conditions:

A. The Director of Production and Conservation or his designee shall require that certificate of deposit be made payable to or assigned to the Commission both in writing and upon the records of the bank issuing the certificate. If assigned, the Director of Production and Conservation or his designee shall require the banks issuing these certificates to waive the rights of setoff or liens against those certificates.

B. The Director of Production and Conservation or his designee shall not accept an individual certificate of deposit in an amount in excess of the maximum insurable amount as determined by the Federal Deposit Insurance Corporation or the Federal Savings and Loan Insurance Corporation.

C. Any interest accruing on a certificate of deposit shall be for the benefit of the permit holder except that accrued interest shall first be applied to any prepayment penalty when a certificate of deposit is forfeited by the Commission.

D. The Certificate of deposit, if a negotiable instrument, shall be placed in the Commission's possession. If the certificate of deposit is not a negotiable instrument, a withdrawal receipt, endorsed by the permit holder, shall be placed in the Commission's possession.

4. Cash submitted in the form of personal or corporate check, money order, or cashiers check to be deposited in the Commission's authorized bank account.

e. Financial Assurance shall be required for:

1. all holders of permits to drill and/or operate gas well(s), and all Class II disposal wells injecting fluids associated with dry gas production wells; and

2. all permit holders of commercial Class II disposal wells; and

3. all permit holders of brine production and Class V brine disposal well(s), and

4. all permit holders of other types of wells or exploratory holes or wells, and

5. all permit holders of liquid hydrocarbons production wells and Class II disposal and enhanced oil recovery injection wells operated in conjunction with liquid hydrocarbon wells, whom have not been a permit holder of record with the Commission for a minimum of two calendar years preceding the date of the application specified in section (b) above.

f. When a permit holder is required to submit Financial Assurance, the minimum amount of the Financial Assurance shall be:

1. $3,000 per well for an oil and /or gas production well, Class II Enhanced Recovery well; brine production well, water supply well, or other type of exploratory hole or well; or

2. $25,000 for a Class II Disposal or Class V Brine Disposal wells; or

3. $50,000 for a Class II Commercial Disposal well; or

4. A blanket financial assurance as follows:

   A. $25,000 for 1-25 wells; or

   B. $50,000 for 26-100 wells; or

   C. $100,000 for 101 or more wells.

g. The Director of Production and Conservation or his designee is authorized to approve administratively each financial assurance instrument required to be filed with the Commission. The Director is further authorized to require additional financial assurance based on but not limited to how long a permit holder has operated in the State, environmental consideration of the well location, and other factors impacting the cost of plugging the well and restoring the associated well site, and the compliance history of the permit holder.

h. Effective January 1, 2006, financial assurance in the form of annual fees shall be paid, by all permit holders of liquid hydrocarbon wells and any Class II Disposal or Class II Enhanced Recovery wells associated with liquid hydrocarbon wells, as follows:

1. Fees shall be assessed annually for all issued permits and wells of record as of January 1 of each year.

2. All assessed fees shall be paid in full by March 1 of each year, after which time the permit holder's Authority to Produce and Transport and Authority to Dispose and/or Inject will be terminated until all delinquent fees are paid.

3. The permit holder shall remain liable for the payment of such fees until the well or wells under permit to the permit holder are plugged and restored; or the well or wells have been transferred to a new permit holder pursuant to Commission rules. Liability for payment of annual well fees ceases on the date when the well has been plugged and restored, or on the effective date stated on the Commission's Notification of Transfer form.

4. If a permit holder's fee check is returned due to insufficient funds or because payment was stopped, the permit holder is required to repay fees for that year by cashiers check or money order.

i. A permit holder may administratively contest the amount of the fee assessment as follows:

1. By submitting a written objection to the assessment amount on or before March 1 of each year. The objection must be accompanied by the full assessed amount.

2. The objection must be in writing, signed by the permit holder, or by an individual authorized to sign for the permit holder, and must identify the nature of the objection. The written objection must include a statement of the facts supporting the objection and copies of any relevant documents to support the objection.

3. The Director of Production and Conservation or his designee shall review the application, and has the authority to amend the fee assessment and refund any monies due the permit holder.

j. The amount of annual fees assessed each January 1 to all permit holders of liquid hydrocarbon and associated Class II wells shall be as follows:

1.	1–5 Permits or Wells	$100/Well
2.	6–15 Permits or Wells	$750/Operator
3.	16-50 Permits or Wells	$1,250/Operator
4.	51-150 Permits or Wells	$2,000/Operator
5.	151-300 Permits or Wells	$3,000/Operator
6.	301 or more Permits or Wells	$4,000/Operator

k. Permit holder's failure to comply with the Commission's order to plug, replug or repair a well, or to restore a well site, within thirty (30) days of the issuance of such order constitutes grounds for forfeiture of the financial assurance held by the Commission, as follows:

1. The Director shall send written notification by certified mail, return receipt requested, to the Permit Holder and the issuer of the financial assurance, if any, informing them of the Director's determination to forfeit the financial assurance for failure to comply with the above Commission Order.

2. The Director may allow the financial assurance issuer to undertake necessary plugging, replugging, repair or site restoration work if the financial assurance issuer can demonstrate an ability to complete such work in accordance with Commission rules. No financial assurance liability shall be released until the successful completion of all plugging, replugging, repair or site restoration ordered by the Commission.

3. In the event forfeiture of the financial assurance is warranted under the provisions of this rule, the Director shall afford the permit holder the right to a hearing, if such hearing is requested in writing by the Permit Holder within fifteen (15) days after the forfeiture notification is mailed in accordance with subsection (1). If the permit holder does not request a hearing within the fifteen (15) day period, the Director shall issue a final decision ordering forfeiture and collection of funds. If a hearing is requested by the permit holder, the hearing shall be docketed for the next regularly scheduled Commission hearing.

4. At the forfeiture hearing, the Director shall present evidence in support of the determination for financial assurance forfeiture. The Permit Holder shall present evidence contesting the Director's determination. The Commission may administer oaths and affirmations, subpoena witnesses and written or printed materials, compel attendance of witnesses or production of those materials, compel discovery, and take evidence, necessary to render a decision.

5. Within thirty (30) days after the close of the record for the forfeiture hearing, the Commission shall issue findings of fact, conclusions of law and the disposition of the case.

(Source: 1992 rule book; amended (Order 27-95) June 20, 1995; amended (Order 4-99) March 23, 1999; amended January 15, 2006; amended October 15, 2006; amended November 16, 2008; amended June 5, 2009)

RULE B-3: SPACING OF WELLS

a. For purposes of this rule and with respect to all established field rules, exploratory drilling units, wildcat wells, and in uncontrolled areas, the term well location shall be defined as follows:

(1) For the purpose of well drilling permit issuance, well location is defined as the proposed bottom hole location in a vertical or directionally drilled well or the estimated productive portion of a lateral in a horizontal well, projected to the surface. For purposes of assigning an API number the well site location shall be considered the actual surface location of the well.

(2) For the purpose of well setback provisions, except in uncontrolled areas, well location is defined as the actual physical location of the completed interval in the well, projected to the surface, as follows:

A. In a vertically drilled well without a directional survey, the well location is the surface location. In a vertically drilled well, the well location is the location of the perforated interval of the well bore, projected vertically to the surface;

B. In a directionally drilled well, the well location is the location of the midpoint of the perforated interval of the producing formation, as calculated from the directional survey, projected vertically to the surface;

C. In a horizontally drilled well, the well location is the entire perforated length of the lateral section of the well bore, as shown on a directional survey, projected vertically to the surface.

b. The spacing of wells in oil and gas fields established by Commission Order, shall be governed by field rules for that particular field, adopted after notice and hearing.

c. The spacing of wells in other areas designated as prospective of oil and gas production shall be governed by General Rule adopted after notice and hearing.

d. The well location for a well drilled for oil or gas production in an exploratory drilling unit established by Commission Order shall not be located closer than 280 feet from the drilling unit boundary, except that wells drilled in exploratory drilling units established by General Rule B-43 or General Rule B-44, shall be governed by the applicable well setback provisions of General Rule B-43 or General Rule B-44, respectively.

e. The following applies to all wildcat well locations not drilled in exploratory drilling units:

(1) The well location for a wildcat well drilled for oil or gas production purposes, within an area not covered by Field Rules, General Rule B-43, or General Rule B-44shall not be located closer than 280 feet from a quarter, quarter division line within a governmental section.

(2) The well location for a wildcat well, drilled for the purposes of oil or gas production, within an area subject to Field Rules, but proposed to be drilled to a geologic formation for which Field Rules have not been established shall be subject to the set back provisions specified in e (1) above.

f. The well location for a well drilled for oil or gas production purposes, and completed in pools in field(s) where Field Rules do not exist for these uncontrolled pools, shall not be located closer than 280 feet from the nearest mineral lease line.

g. The following applies to injection wells drilled or completed for enhanced recovery, Class II Disposal Wells, or Class II Commercial Disposal Wells (as defined by General Rule H-1):

(1) The well location for an injection well drilled or completed for enhanced recovery purposes shall not be located closer than 280 feet from a unitized boundary line.

(2) The well location for a Class II Disposal Well, or Class II Commercial Disposal Well, drilled or completed pursuant to General Rule H-1 shall be located no closer than 280 feet from the drilling unit boundary in controlled fields.

(3) The well location for a Class II Disposal Well or Class II Commercial Disposal Well, drilled or completed pursuant to General Rule H-1, outside of a controlled field and not within an uncontrolled field, shall be located no closer than 280 feet from a quarter, quarter division line within a governmental section.

(4) The well location for a Class II Disposal Well, or Class II Commercial Disposal Well, within an uncontrolled field, drilled or completed pursuant to General Rule H-1 shall be located no closer than 280 feet from the mineral lease line. However, with regards to Class II Disposal Wells, this requirement may be waived by the Director if the offset operator(s) which is being encroached upon gives written permission for the Class II Disposal Well to be located at a closer distance and waives the requirement of a hearing before the Commission to the operator of the Class II Disposal Well and the appropriate AOGC Regional Office.

h. The well location for wells drilled for the purposes of water supply for purposes of enhanced oil recovery are subject to all the provisions of this rule with the exception of the set back provisions for well location. No production of hydrocarbons will be allowed from a water supply well.

i. The Commission may, after notice and hearing, grant exceptions to the rule, provided such exceptions will create neither waste nor hazards conducive to waste. No well drilled in violation of this rule without special permit obtained in the manner prescribed in said rule and no well drilled under such a special permit, which does not conform to the terms of such special permit in all respects, shall be permitted to produce either oil or gas and any such well so drilled in violation of said rule or in violation of a permit granted under an exception to such rule shall be plugged.

(Source: 1992 rule book; amended November 13, 2005; amended September 16, 2006; amended November 19, 2018)

RULE B-4: APPLICATION TO TRANSFER A WELL

a) Definitions

1) "Current Permit Holder" means the person required to hold the permit or to whom the permit was issued and who is the owner of the right to drill, produce and/or operate said well(s), possesses the full rights and responsibilities for operating the well(s) in accordance with applicable Arkansas law and/or rule or order of the Commission, and has the current obligation to plug said well(s), who is the assignor, transferor or seller (whether voluntary or involuntary) of the well(s).

2) “Deepen” for a cased well means an operation whereby a well is drilled to a measured depth below the cement casing shoe. For an open hole completion, “Deepen” means an operation whereby a well is drilled below the original measured depth of the well.

3) “Drill” means the commencement of an operation to either set conductor pipe or the moving in a drilling rig capable of drilling to a depth to set the requisite amount of surface casing and spudding the well, if conductor pipe is not used.

4) "New Permit Holder" means person acquiring the well(s) and the right to drill, produce, and/or operate said well(s), who obtains the full rights and responsibilities for operating the well(s) in accordance with applicable Arkansas law and/or rule or order of the Commission, whom will obtain the obligation to plug said well(s), and who as owner or operator in accordance with applicable Arkansas law and/or rule or order of the Commission is required to hold the permit.

5) “Re-enter” means an operation whereby surface access to the wellbore is established.

6) “Transfer” means any assignment, devise, release, transfer, takeover, buyout, merger, sale, conveyance, or other transfer of any kind, whether voluntarily or involuntarily.

7) “Well” means a production well as defined by General Rule B-1.

b) The provisions of this rule apply to all transfers of the interest of the person required to hold and to whom the well transfer approval is issued (Permit Holder), including but not limited to:

1) A change of ownership of the right to drill, produce and/or operate well(s), including the obligation to ultimately plug said well(s); or

2) A change in the designation of the owner or operator under an operating or other similar agreement; or

3) A change pursuant to the action of the owners of separate interests who designate an owner to be Permit Holder; or

4) A change required by the appointment, by a court of competent jurisdiction, of a trustee or a receiver to exercise custody and control over the well(s), including the right to drill, produce and/or operate well(s), and the obligation to ultimately plug said well(s)

c) The provisions of this rule shall not apply to the transfer of the royalty, overriding royalty or fractional working interests not affecting the rights or responsibilities of the Permit Holder.

d) The provisions of this rule shall not apply to transfers of well(s) abandoned or orphaned in accordance General Rule G-1 or G-2. Transfers of well(s) deemed abandoned or orphaned are subject to the transfer provisions in General Rule G-3.

e) Notification of a transfer shall be given to the Director, or his designee, by the Current Permit Holder on a form prescribed by the Director.

f) A separate form shall be completed for each lease, well, or other unit transferred.

g) The notification shall be signed by the Current Permit Holder and the New Permit Holder, or by authorized representatives specified on the Organizational Report filed in accordance with General Rule B-13, except as follows:

1) In lieu of the signature of the Current Permit Holder, the New Permit Holder may submit a court order or other legal document evidencing ownership of the lease or unit to be transferred in the event that the Current Permit Holder cannot be located or refuses to sign the notification of transfer form.

2) In lieu of the signature of the New Permit Holder, the Current Permit Holder may submit documentation evidencing transfer of the ownership of the well, lease, or unit in the event the New Permit Holder refuses to sign the notification of transfer form.

h) Prior to the Director, or his designee, approving the transfer request, the New Permit Holder shall:

1) Be authorized to do business within the State of Arkansas; and

2) Provide the required financial assurance, if applicable, in accordance with General Rule B-2 and subparagraphs h) 4) and h) 5) below; and

3) File the required organizational report, if applicable, in accordance with General Rule B-13; and

~~4)~~ If the transfer is for a gas well producing less than 25 MCF/day per AOGC records, or a well that has received an approved temporarily abandonment status in accordance with General Rule B-7, then the Current Permit Holder and New Permit Holder may file an application, on a form prescribed by the Director, requesting administrative approval of the transfer request.

a. If the transfer request is approved administratively, the New Permit Holder shall file an additional, well specific financial assurance of $35,000 for each natural gas well in a form authorized by General Rule B-2.

b. If the transfer request is denied, or if the Director notifies the Current Permit Holder and the New Permit Holder that he is referring the request to the Commission, the Current Permit Holder and New Permit Holder may file an application in accordance with General Rules A-2, A-3, and other established hearing procedures to have the Commission review the transfer request.

i. If the transfer request is approved by the Commission after notice and hearing as provided above, the New Permit Holder shall file an additional, well specific financial assurance of $35,000 for each natural gas well in a form authorized by General Rule B-2, unless otherwise provided by the Commission after notice and hearing.

5) If the transfer is for a liquid hydrocarbon production well and the well has received an approved temporarily abandonment status in accordance with General Rule B-7, then the New Permit holder is required to replace any amount of well specific financial assurance that is required by the Current Permit Holder, unless otherwise provided by the Commission after notice and hearing, prior to transfer.

i) A transfer to a New Permit Holder shall be denied by the Director, or his designee, if:

1) The New Permit Holder has not fully satisfied all applicable requirements.

2) The Commission has not approved the transfer in accordance with h) 4) above; or

3) The New Permit Holder has falsified or otherwise misstated any material information on or relative to the transfer application; or

4) No further permits or authorities may be issued in accordance with General Rule A-5 e) 12); or

5) The Director, or his designee, deems it necessary that the transfer request be denied for the purpose of protecting correlative rights of all parties, or to prevent waste as defined by Ark. Code Ann. §15-72-102.

j) The New Permit Holder shall be responsible for all regulatory requirements relative to all wells and all other surface facilities in existence at the time of the transfer related to the well(s). The New Permit Holder shall not be responsible for regulatory requirements relative to spills of crude oil or other production fluids which occurred prior to the date of the transfer, unless the New Permit Holder has otherwise agreed with the Current Permit Holder.

k) If any well, or any lease or other unit associated with the well, is in violation at the time of the transfer request to the New Permit Holder, the transfer request shall be denied pending abatement of all violations by the Current Permit Holder. However, if the New Permit Holder, after being notified of the violation(s), agrees in writing to the transfer approval including conditions to abate all violations, the transfer may be approved by the Director, or his designee in accordance with this Rule. Failure to abate the violations within the time period specified by the Director or his designee may result in revocation of the transfer approval in accordance with subparagraph (o) below, and/or other applicable enforcement actions in accordance with General Rule A-5.

l) The Current Permit Holder is not responsible for any regulatory violation caused by the actions of the New Permit Holder during the permit transfer process. However, if the transfer is denied by the Director, or his designee, the Current Permit Holder assumes all responsibility for the violations caused by the New Permit Holder. Nothing in this subparagraph shall affect the contractual rights and obligations between the person or entity transferring the well(s) and the person or entity acquiring the well(s).

m) The transfer request shall not affect the rights of the Commission, or any obligation or duty of the Current Permit Holder arising under any applicable Arkansas laws, or rules or orders of the Commission.

n) The Director shall notify the Current and New Permit Holder of the transfer approval or denial in writing. Following the approval or denial of the transfer approval request, the Current or New Permit holder shall have thirty (30) days from the date of the approval or denial to appeal the Director's Decision in accordance with General Rule A-2, A-3 and other applicable hearing

procedures. A transfer request approval or denial, for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the approval or denial.

o) Well Transfer Revocation Procedures

1) The Director may revoke a well transfer approval if the Permit Holder fails to meet permit conditions as specified in the well transfer approval, the well transfer approval was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the well transfer revocation in writing. Following the revocation notice the Permit Holder is required to plug the well. The Permit holder shall have thirty (30) days from the date of the well transfer revocation to appeal the Director's Decision to revoke the well transfer approval in accordance with General Rule A-2, A-3 and other applicable hearing procedures. Drilling, production, or operation may not commence or continue during the appeal process. A revocation of a well transfer approval for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

(Rule Repealed Effective November 11, 2007; New Rule Effective November 19, 2018; amended May 08, 2022)

RULE B-5: SUBMISSION OF WELL RECORDS AND ISSUANCE OF CERTIFICATE OF COMPLIANCE

a. During the drilling, original completion, recompletion, or workover of every well, the owner, operator, contractor, driller or other person responsible for the conduct of drilling, original completion, recompletion or workover operations, shall keep adequate records of the well being drilled, all of which shall be accessible to the Commission and its agents at all reasonable times.

b. For purposes of this rule, original completion shall be defined as initial zone perforation, and configuration of wellhead for production, excluding pipeline connections. Any further completion work, after the initial configuration of the wellhead, shall be considered a recompletion or workover, and subject to the filing requirements of Section (d) or (f) below.

c. For purposes of this rule, recompletion is as defined in General Rule A-4.

d. For purposes of this rule, workover is as defined in General Rule A-4. Upon completion of workover operations, only well records specified in Section (f)(1)(3) are required to be submitted.

e. Wells drilled as dry holes, where production casing has not been set, shall be subject to the well record submission requirements specified in Section (f) (1), (2) and (3) within 30 days after the completion of drilling activities.

f. Upon original completion or recompletion of the well, the operator, contractor, driller, or other person responsible for the conduct of the drilling operation shall file with the Commission:

1. Properly filled out Well Completion Report.

2. All electric logs or other geophysical logs of the open well bore, which measure resistivity, porosity, temperature, and gamma ray emission and for planned directional and horizontal wells, borehole deviation and direction logs including a true vertical depth logs, to be submitted in a 1 inch, 2 inch and 5 inch to 100 foot scale format or other scale format acceptable to the Commission. All logs shall be submitted, at a minimum, as paper copies in standard continuous logging paper format. If electronic copies of the logs can be provided from the logging service company, the operator is also required to submit copies of the electronic logs in either LAS (ASCII Format) or raster format image (200 DPI Black & White in TIF, JPG, BMP) to the Commission on an approved electronic storage device. If electronic copies of the logs cannot be provided by the logging service company, the operator shall file an affidavit with the Commission stating electronic logs could not be provided by the logging service company.

3. All logging and well service company tickets applicable to the completion or recompletion operation which indicate all logging and completion activities occurring in the well.

4. Properly filled out Request for Certificate of Compliance.

5. Application to Abandon other than for a dry hole

g. For directional or horizontal wells, or deviated wells not in compliance with General Rule B-30, the following shall also be submitted:

(1) A post drilling plat shall be filed with any Completion and Recompletion Report to demonstrate the actual location of all vertical, directional and horizontally drilled boreholes in the drilling unit. The plat should provide and present the following:

A. The locations of all wells which have been drilled within the drilling unit (except for those wells that have been plugged and abandoned), by providing their surface and bottom hole location, and either midpoint perforations for deviated or directionally drilled wells or the closest point along any lateral section of the horizontal portion of the well bore (whichever is applicable) measured to the nearest mineral lease, drilling unit or division line within a governmental section, whichever applies to the established drilling unit in that field; and

B. The distance between common sources of supply for which an allowable determination is required; and

C. The actual location of the entire perforated length of the lateral section in a horizontal well showing the set back distances to offset wells.

(2) A directional survey in table form, accompanied by the following:

A. A two dimensional cross section diagram, viewed perpendicular to the axis of maximum lateral borehole displacement, which depicts the measured and true vertical depth and the displacement from vertical of the wellbore; and

B. An azimuth plot viewed in plan view providing displacement of the well path from the surface location.

h. The above reports shall be filed within 30 days of the original completion, recompletion or workover of the well and prior to commencement of production. Upon receipt of the required information specified in Section (f) (1), (2) and (4), and Section (o) (8) of General Rule B-43 if applicable, a Certificate of Compliance shall be issued granting authority to produce and transport oil and/or gas for a period of 30 days at which time the required information specified in Section (f) (3) must be on file in order for a final Permit to Produce and Transport to be issued. However, if completion activities are not completed within 90 days of the setting of the production casing or other production related casing, the required information specified in (f) (1), (2) and (3) are required to be submitted, pending submission of final reports at the conclusion of completion activities and a request for a Certificate of Compliance.

i. Failure to comply with the provisions of this rule shall be sufficient reason to cause the suspension of the issuance of any further drilling permits on a statewide basis to that operator until the required information is submitted to the Commission, within 10 days following written notice provided to the operator of the failure to provide the required information.

j. If an operator makes a request, in writing, that the log described in Section (f) (2) be kept confidential, the request will be honored for a period not to exceed 90 days after the logging for completion or abandonment of the well, provided that the report or the data thereon, when pertinent, may be introduced in evidence in any public hearing before the Commission or any court, regardless of the request that such record be kept confidential.

(Source: 1992 rule book; amended September 16, 2006; amended January 14, 2008; amended May 11, 2008)

RULE B-6: OIL, GAS AND WATER TO BE PROTECTED

Before any well or any producing horizon encountered therein shall be abandoned, the owner or operator shall use such means, methods and procedures as may be necessary to prevent water from entering any oil or gas-bearing formations, and to protect any underground or surface water that is suitable for domestic or irrigation purposes from waste, downward drainage, harmful infiltration and addition of deleterious substances.

(Source: 1992 rule book)

RULE B-7: WHEN WELLS SHALL BE PLUGGED AND ABANDONED AND NOTICE OF INTENTION TO PLUG AND ABANDON WELLS

a) The current permit holder is responsible for plugging wells as defined in this rule. In the case of leaking wells, plugging responsibility is in accordance with General Rule B-26 (k) and (l).

b) All new wells drilled for liquid hydrocarbons, natural gas, or brine exploration, or brine production, water supply or injection purposes, except such holes as are described in Rule B-10, regardless of depth are required to be either properly cased with production casing or the uncased well or dry hole shall be plugged and abandoned in accordance with applicable commission rules, unless an extension of time to plug is granted in accordance with subparagraph (c) below.

c) Uncased wells and dry holes

1) Any well in which production casing is not set and cemented shall be plugged in accordance with applicable commission rules, prior to the time that the equipment used to drill said well is released from the drilling operation. In the case of "staged" drilling operations, where multiple drilling rigs are used to drill the well over a period of time, production casing shall be set and cemented within 180 days after setting of the surface casing or the well shall be plugged, unless an extension of time to plug is granted in accordance with subparagraph 2) below.

2) The Director however, may grant an extension of time to plug an uncased well. In determining whether to grant an extension and in determining the length of an extension, the Director may consider:

A) The permit holders specific plans for further wellbore utilization,

B) The total depth of the well,

C) The depth of surface and any intermediate casing,

D) A description of the current condition of the hole including a description of the type of drilling fluids currently in the well,

E) The location of the well.

3) If the Director determines that the uncased well presents a risk of contamination to the environment or a risk to public safety the Permit Holder shall be required to repair, case, plug or perform other remediation measures to the well, as determined by the Director, within twenty four (24) hours after notification by the Director.

d) All cased wells utilized for liquid hydrocarbons, natural gas or brine production, water supply or injection purposes, except such holes as are described in Rule B-10 or liquid hydrocarbons production wells located on actively producing leases, shall be plugged and abandoned in accordance with applicable commission rules after the well has been idle for more than 24 months, or sooner should the Director determine that the cased well presents a risk of contamination to the environment or a risk to public safety, unless an application is filed to request temporary abandonment status for the well in accordance with subparagraph h) below. Upon such determination by the Director or if temporary abandonment status is denied, the Permit Holder shall commence plugging the well within 30 days after notification by the Director. Failure to commence plugging the well within 30 days after notification by the Director

may result in the initiation of well abandonment proceedings in accordance with General Rule G-1.

e) Prior to the commencement of any work in plugging and abandonment operations, the permit holder or other person responsible for the conduct of the drilling operations shall give notice of the intent to plug and abandon such well in a form prescribed by the Director as follows:

1) For uncased wells and dry holes, notice shall be provided via verbal or facsimile communication to the Commission Regional Office where the well is located, as soon as possible, but no less than 8 hours, prior to commencement of plugging operations.

2) For cased wells, written notice on a form prescribed by the Director shall be provided to the Commission Regional Office where the well is located, at least 72 hours prior to the commencement of plugging operations.

f) Upon receipt and review of such verbal or written notice, the Commission Regional Office shall authorize the commencement of plugging operations and may send a duly authorized Commission representative to the well location to witness the plugging of such well.

g) Authorization to plug and abandon is not granted unless the appropriate notice, as specified in subparagraph (e) above, has been provided to the Oil and Gas Commission by the permit holder or person responsible for the plugging of the well. Plugging of the well without providing proper notice as required can result in the Permit Holder being required to drill out the well plugs and the well replugged under Commission observation.

h) Temporary Abandonment Status

1) An application for temporary abandonment status shall be made on form prescribed by the Director and, if approved, shall be valid for a period not to exceed three (3) years from the date of the Director's approval. At the expiration of the three (3) year period the Permit Holder shall commence plugging operations within thirty (30) days, or file an application to request a hearing before the Commission in accordance with General Rules A-2, A-3 and other applicable hearing procedures to request an extension of the three (3) year period of the temporary abandonment status. Wells in an approved waterflood/enhanced oil recovery unit are exempt from the initial three (3) year time limit as long as the unit remains active.

2) Wells which have not produced for more ten (10) years are not eligible for approval by the Director of temporary abandonment status, unless the well is in an approved waterflood/enhanced oil recovery unit that remains active. Temporary abandonment status for these wells may only be granted by the Commission after notice and a hearing in accordance with General Rule A-2, A-3 and other applicable hearing procedures.

3) Temporary abandonment status shall be approved by the Director provided:

A) Financial Assurance in the amount of $35,000 per well for any dry natural gas production well, or $15,000 per well for any liquid hydrocarbon production well is submitted for each well. The Financial Assurance shall be in a form as prescribed by General Rule B-2, and shall remain valid until the well is put back into sustained production, plugged or transferred, and

B) The well is secured with a suitable wellhead with no leakage of any substance at the surface, and

C) The well site is maintained in accordance with General Rule B-26 i), and

D) Proper well identification is maintained in accordance with General Rule B-26 b), and

E) Useable groundwaters are protected utilizing one of the following methods:

i) Set a drillable, retrievable or other type of mechanical bridge plug above the producing interval, in the cemented portion of the production casing, but at least 150 feet below the base of the lowest usable groundwater in the area, and secured at the surface with a wellhead and valve in operable condition; or

ii) Set a packer run on tubing above the producing interval, in the cemented portion of the production casing, but at least 150 feet below the base of the lowest usable groundwater in the area, and secured at the surface with suitable wellhead packoff equipment and closed to the atmosphere or with a wellhead and valve in operable condition;

iii) Run a casing inspection log confirming the mechanical integrity of the production casing and secured at the surface with a wellhead and valve in operable condition; or

iv) Conduct a fluid level test by wireline or other approved electronic or mechanical means, which determines that the static fluid level is at least 150 feet below the base of the lowest usable groundwater in the area, and upon no less than 48 hours notice prior to conducting the fluid level test, which may be witnessed by commission staff. The fluid level test shall be conducted annually, within 60 days prior to the anniversary date of the temporary abandonment during each year of the three (3) year temporary abandonment period.

4) Failure to maintain any of the above conditions may result in the issuance of a Notice of Violation ("NOV"). Failure of the Permit Holder to comply with the NOV, or other applicable final administrative decision in accordance with General Rule A-5, shall result in the revocation of the temporary abandonment status and require the well to be plugged in thirty (30) days, unless an extension of time to plug is granted after notice and hearing.

5) Wells returning to active status from temporary abandonment status shall file for authorization to commence production operations on a form prescribed by the Director.

(Source: 1992 rule book; amended December 16, 2007; amended February 19, 2009; amended November 19, 2018)

RULE B-8: PLUGGING METHODS AND PROCEDURES

The methods and procedures for plugging a well shall be as follows:

A. The bottom of the hole shall be filled to the top of each producing stratum and a cement plug of not less than one hundred (100) feet in length shall be placed inside the casing immediately above each producing stratum; or a bridge plug, regular or wireline type, may be placed at the top of each producing stratum. In the event bridge plugging is to be used for permanent abandonment, the bridge plug must be covered with a minimum of ten (10) feet of cement; the casing must be free from openings, except perforations for the injection or producing formation and the casing well bore annulus must be filled with cement to fifty (50) feet above the top of the formation.

B. A cement plug not less than one hundred (100) feet in length shall be placed at approximately fifty (50) feet below all fresh water-bearing stratum when the surface casing is not cemented below the base of the fresh water-bearing stratum. In the event the surface casing has been cemented below the base of the fresh water-bearing stratum, a one hundred (100) foot cement plug shall be placed inside the base of the surface casing.

C. A plug shall be placed at the surface of the ground in each hole plugged in such manner as not to interfere with soil cultivation.

D. The interval between plugs shall be filled with an approved heavy mud-laden fluid.

E. An uncased rotary drilling hole shall have a cement plug of not less that one hundred (100) feet placed immediately above (1) the Smackover limestone zone and (2) any known productive zone in the area, and the hole shall be filled with approved heavy mud up to the base of the surface casing and a plug of not less than one hundred (100) feet of cement placed inside the base of the surface casing, provided the casing is cemented through the base of the fresh water-bearing stratum. A cement plug of not less than one hundred (100) feet in length shall be placed at a point fifty (50) feet below the base of the fresh water-bearing stratum in the event the surface casing is not cemented through the base of the fresh water-bearing stratum. The hole shall be capped similar to other abandoned holes.

F. Any other method approved by the Commission may be used.

(Source: 1992 rule book)

RULE B-9: DRY GAS WELL PLUGGING METHODS AND PROCEDURES

a) Definitions:

1) "Cased Well" means a well in which production casing has been set and cemented.

2) "Cement" means a class A or H neat cement with a minimum weight of 14.5 pounds per gallon, unless the cement contains additives which improve the ability of the cement to provide necessary protection and which maintains a minimum compressive strength of 500 PSI after 72 hours.

3) "Circulation Method" means placement of cement used in plugging a well by circulating cement by positive pressure displacement through tubing set at a specified depth in the well.

4) "Dump Bailer Method" means placement of cement used in plugging a well by using a dump bailer on a wire line.

5) "General Oilfield Waste" means oily rags, chemical containers including any unused chemicals, oil filters and gaskets, used motor oil, lubricating oils, hydraulic fluids, diesel fuels, paint and solvent wastes and other similar wastes generated during drilling, completion, production, workover and plugging activities and which are not exempt from the provisions of Subtitle C of the Federal Resource Conservation Recovery Act of 1976.

6) "Mud" means only a fresh-water based drilling mud with a minimum weight of 9 pounds per gallon with a minimum viscosity of 45 seconds using API Full Funnel Method. Mud may contain water (fresh or brine), Bentonite, Attapulgite or other additives if they do not reduce the weight or viscosity below the required minimum.

7) "Plugging Fluid Waste" means plugging fluids, including cement, that are generated from the well during plugging activities.

8) "Uncased Well" means a well in which production casing has not been set or is set, but not cemented.

b) Uncased Wells

1) Uncased wells shall be plugged when required by General Rule B-7.

2) Notice of the plugging of uncased wells shall be given to the Commission Regional Office where the well is located, in accordance with General Rule B-7. Following initial notice to the Commission Regional Office, additional requirements concerning the well plugging operation, may be given to the Permit Holder or the Permit Holder’s authorized representative.

3) Uncased wells where intermediate casing has been set, shall be subject to all the required plugging time frames for uncased wells and the applicable plugging requirements for cased wells in (c) below with respect to the protection of freshwater and oil and gas zones.

4) Plugging Requirements

A) The uncased well bore shall be filled with mud from the total depth of the well to the base of the surface casing prior to commencing plugging operations.

B) Any zones which have been productive of oil and or gas occurring in wells within ½ mile of the uncased well, shall have a one hundred (100) foot cement plug placed above each such correlated interval in the uncased well.

C) A zone which contains any amount of hydrogen sulfide gas, or any other zone within the well which does not contain hydrogen sulfide gas, but hydrogen sulfide gas is present within the same zone within any well within one-half (1/2) mile, shall be covered, at a minimum, with a cement plug from one hundred (100) feet below to one hundred (100) feet above the zone or with a greater amount of cement sufficient to shut-off and control the flow of hydrogen sulfide gas.

D) If surface casing has been set to a depth of at least five hundred (500) feet in the well, a one hundred (100) foot cement plug shall be placed, utilizing the circulation method, from a depth of fifty (50) feet below the base of the surface casing, or from the depth of any deeper freshwater well within ½ mile of the dry hole, and extending fifty (50) feet into the cemented surface casing.

E) If surface casing has not been set to a minimum depth of five hundred (500) feet in the well, a cement plug shall be placed, from a depth of at least five hundred (500) feet or from the depth of any deeper freshwater well within one-half (½) mile of the dry hole, extending to fifty (50) feet into the cemented surface casing.

F) Any zones not covered by the surface casing plug specified above, which produced water during the drilling or subsequent plugging operations, shall be covered at a minimum, with a cement plug from fifty (50) feet below to fifty (50) feet above the zone or a greater amount of cement sufficient to shut-off the flow of water.

G) A cement plug shall be placed from a minimum depth of fifty (50) feet to a depth of three (3) feet below the surface of the ground and the casing cut off three (3) feet below the ground surface, or deeper if surface use conditions indicate, and a plate welded onto the top of the casing and the remaining wellbore filled with soil and leveled in such manner as not to interfere with soil cultivation or surface use.

5) In the case of lost tools or stuck drill pipe, every reasonable attempt should be made to recover the tools or drill pipe, at least to a depth of the required surface casing plug, and the required surface casing plugs placed as required above. In the event the lost tools or stuck drill pipe cannot be recovered from a depth below the required depth of the surface casing plug, the Director may vary the plugging requirements of this subparagraph and specify alternative plugging requirements. In determining whether to approve and in selecting an alternative plugging requirement, the Director shall consider the potential for damage to fresh water, the depth of the lost tools or equipment in relation to the depth of fresh water zones, well construction characteristics, and the potential for upward migration of wellbore fluids into the fresh groundwater.

c) Cased Wells

1) Cased wells shall be plugged when required by General Rule B-7.

2) Notice of the plugging of cased wells shall be given to the Commission Regional Office where the well is located, in accordance with General Rule B-7.

3) Plugging Requirements

A) The wellbore shall be filled with mud from total depth of the well to the base of the surface casing prior to commencing plugging operations.

B) Cast iron bridge plugs may be set above the lowermost perforated interval or between perforated intervals prior to filling the wellbore with mud, in which case the wellbore need only be filled with mud from the top of the uppermost cast iron bridge plug to the base of the surface casing prior to commencing plugging operations.

C) If using the circulation method, a cement plug of not less than one hundred (100) feet in length, shall be placed from fifty (50) feet below, or total depth if well bore did not extend to a point fifty (50) feet below, and extend across the perforated interval, to a point fifty (50) feet above each perforated interval.

D) If using the dump bailer method, a cast iron bridge plug, shall be placed inside the cemented portion of the production casing, immediately above each perforated interval, with each bridge plug covered with a minimum of ten (10) feet of cement. In the alternative a cast iron bridge plug may be placed over the lower most perforated interval and the wellbore casing filled with cement to a point fifty (50) feet above the top of the uppermost perforated interval, provided the production casing/wellbore annulus is filled with cement to a point fifty (50) feet above the uppermost perforated interval.

E) If cement is not present on the outside of the production casing at the location of each required cement plug, specified in F), G) and H) below, cement shall be placed on the outside of the production casing in the production casing/wellbore annulus from a point fifty (50) feet below, or total depth if the well bore did not extend to a point fifty (50) feet below, and extending across the required interval to be plugged, to a point fifty (50) feet above each required interval to be plugged. However, the Director may approve alternative, but equally protective, placement of cement plugs, openhole devices or plugging materials when necessary due to well construction limitations.

F) Any zones not covered by the surface casing, which produce water during the plugging operation or are known to be significant water producing formations or which are known to be over-pressured, shall be covered at a minimum, with a cement plug from fifty (50) feet below to fifty (50) feet above the zone or a greater amount of cement sufficient to shut-off the flow of water. The Director may approve alternative, but equally protective, plugging materials or other open-hole devices sufficient to shut-off the flow of water.

G) If surface casing has been set to a minimum depth of five hundred (500) feet in the well, a one hundred (100) foot surface casing cement plug shall be placed, on the outside and inside of the production casing if production casing is not removed, from a depth of fifty (50) feet below the base of the surface casing, or from the depth of any deeper freshwater well within ½ mile of the wellbore, and extend fifty (50) feet into the cemented surface casing.

H) If surface casing has not been set to a minimum depth of five hundred (500) feet in the well, a cement plug shall be placed, on the outside and inside of the production casing, if production casing is not removed, from a depth of at least five hundred (500) feet or from the depth of any deeper freshwater well within ½ mile of the well bore and extend fifty (50) feet into the cemented surface casing present in the wellbore. However, if it can be demonstrated that no freshwater bearing zones are present below the existing surface casing set in the well, the Director may approve an alternative surface casing plug extending from fifty (50) feet below the existing surface casing and extending fifty (50) feet into the cemented surface casing present in the wellbore.

I) The casing shall be cut off three (3) feet below the ground surface, or deeper if surface use conditions indicate, and a plate welded onto the top of the casing and the remaining wellbore filled with soil and leveled in such manner as not to interfere with soil cultivation or surface use. A cement plug, not less than three (3) feet, shall be also be placed below the plate that is welded onto the top of the casing.

4) Foreign Material Prohibited

A) Except for an unavoidable loss of drilling and logging tools, production equipment or the presence of damaged casing obstructing the wellbore, placing or lodging any material or substance, in an unplugged well to either fill or bridge the hole for the purpose of avoiding proper plugging procedures is prohibited.

B) Foreign materials which have been placed in the hole shall be removed before plugging operations are commenced.

5) Plugging A Bridged Well

A) When a well becomes obstructed because of the loss of drilling or logging tools or producing equipment, which would be impractical to remove, the Director may vary the plugging requirements of this subparagraph and specify alternative plugging requirements.

B) In determining whether to approve and in selecting alternative plugging requirements, the Director shall consider the time and cost of removing lost tools or equipment, the potential for damage to fresh water, the depth of the lost tools or equipment in relation to the depth of fresh water zones, well construction characteristics, and the potential for upward migration of wellbore fluids into the fresh groundwater.

d) Horizontal Well Plugging Procedures

1) For an uncased well, the plugging procedures shall be in accordance with sub-paragraph (b) above with the exception that (i) the production interval plug shall be placed at the beginning of the well curve “kick-off point” and the required cement placed or extend above that point, and (ii) oil-based drilling mud may be used to fill the horizontal lateral of the wellbore up to the “kick-off point” provided the “kick-off point” is below any known fresh groundwater.

2) For an cased well, the plugging procedures shall be in accordance with sub-paragraph (c) above with the exception that (i) the production interval plug shall be placed at the beginning of the well curve "kick-off point" and the required cement placed or extend above that point, and (ii) oil-based drilling mud may be used to fill the horizontal lateral of the wellbore up to the "kick-off point" provided the "kick-off point" is below any known fresh groundwater.

3) If a vertical "pilot hole" is drilled below the well curve "kick-off point", and the pilot hole encountered another producing interval in the vertical pilot hole below the "kick–off point", a one hundred (100) foot cement plug shall be placed above each such correlated interval encountered in the vertical pilot hole, prior to drilling the horizontal portion of the well, unless approval has been granted to produce the other interval encountered in the pilot hole in accordance with applicable general rules or order of the Commission. Additionally, the Director may approve alternative forms of zonal isolation based on the productive potential of the isolated zone.

4) Well-site clean-up shall be in accordance with sub-paragraph (e) below.

e) Well Site Clean-Up

1) When plugging a well, the permit holder shall provide at least one (1) pit as described in subparagraph e) 2) below, or leak free, above ground, portable container into which plugging fluid wastes shall be deposited.

2) Plugging pits, shall be constructed with sufficient capacity to contain all plugging fluid wastes within the pits, and maintained in a manner that reasonably prevents overflow during plugging operations. Plugging pits shall be used only for the temporary storage of plugging fluid wastes, and shall not be used for the disposal of general oilfield wastes.

3) All general oilfield wastes generated during plugging activities shall be temporarily stored in on-site containers, and shall be removed from the site at the conclusion of plugging activity. General oilfield wastes shall not be disposed of through on-site burial or in plugging pits.

4) All plugging pits shall be filled and graded within thirty (30) days after conclusion of plugging activities, unless an extension has been granted by the Director. All plugging pits shall be closed allowing no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support agriculture or forestry machinery.

5) All production equipment, concrete bases, machinery, and equipment debris shall be removed from the site.

6) Any drilling rat holes shall be filled with mud to a depth of ten (10) feet below the surface, at which point a cement plug shall be placed from ten (10) feet to three (3) feet below ground level and leveled to the surface with soil.

(7) Any other excavations shall be filled and the overall well site graded or contoured to prevent erosion.

f) Alternative plugging methods maybe authorized by the Director, provided the same or equal level of protection for the freshwater and oil and gas zones can be maintained.

(Original rule Repealed Effective October 15, 2006; new rule March 25, 2010; amended October 1, 2015)

RULE B-10: SEISMIC CORE AND OTHER EXPLORATORY HOLES TO BE PLUGGED; METHODS, RECORDS

Before any hole is abandoned which is drilled for seismic, core or other exploratory purposes below the fresh water formation, it shall be the duty of the owner or driller of any such hole to plug the same in such manner as to properly protect all water-bearing formations.

A. Core Holes:

1. Core holes shall comply with the Minimum Surface Casing and Plugging Requirements.

2. No core hole shall be completed as a producing well.

3. A Plugging Record shall be filed no later than thirty (30) days from the date drilling operations commence.

4. A copy of all electric logs shall be filed with the Commission no later than one (1) year from the date drilling operations commence. In the event an electric log was not run, the operator shall file a copy of a driller's log.

5. All information required to be filed shall be kept confidential for a period of one (1) year from the date drilling operations commence.

(Source: 1992 rule book)

RULE B-11: DOMESTIC NATURAL GAS WELLS AND CONVERSION OF PERMITTED OIL AND NATURAL GAS WELLS FOR USE AS DOMESTIC NATURAL GAS OR FRESH WATER SUPPLY WELLS

a) Domestic Natural Gas Wells

1) Any well drilled by persons for use as a domestic, livestock or agriculture natural gas source, is not under the jurisdiction of the Commission and is not subject to permitting or regulation by the Commission, provided such natural gas is not sold or gathered for sale to others. Such wells may be subject to other applicable State laws.

2) If the gas produced from a well operating as a domestic use well is gathered for resale to others, that well is under the jurisdiction of the Commission and shall be subject to all applicable regulatory requirements of the Commission and any other applicable state laws regarding the production, gathering and distribution of natural gas for use by consumers.

b) Domestic Use Transfer(s) after November 16, 2008.

1) A controlled natural gas production well, required to be permitted by the Commission, may be transferred to a surface owner for use as a domestic natural gas supply well if the well has not produced commercial quantities of natural gas during the previous twenty four (24) calendar months provided:

A) The operator files, on a form prescribed by the Director, a request to transfer the well to the surface owner, which shall include written documentation from the surface owner accepting transfer of the well for use as a domestic natural gas supply well; and

B) A statement by the surface owner and the operator that the natural gas from the well will be used on the property where the well is located and that any natural gas production from the well will not be sold; and

C) Written documentation from all owner(s), as defined in Ark. Code Ann. § 15-72-102 (9), and all mineral owners in the drilling unit upon which the well is located, stating that they do not object to the transfer of the well to the surface owner.

2) An oil or natural gas production well may be transferred to a surface owner for use as a domestic or livestock freshwater supply well provided:

A) The operator files, on a form prescribed by the Director, a request to transfer the well to a surface owner prior to commencing plugging operations, which shall include written documentation from the surface owner accepting transfer of the well for use as a freshwater supply well; and

B) The well is plugged in accordance with current Commission plugging requirements with respect to all oil and natural gas producing zones and a cement plug is placed, on the inside and outside of the production casing if left in the well, from 100 feet below the base of the fresh water extending up to the base of the fresh water in the well; and

C) All related surface production equipment is removed from the well site.

3) Following completion of the above domestic use well transfer requirements, all regulatory oversight of the well by the Commission shall terminate and the well shall become the sole responsibility of the surface owner. The well shall be subject to any applicable state laws regarding private fresh water wells or domestic natural gas supply wells administered by state and or federal agencies other than the Arkansas Oil and Gas Commission.

c) Uncontrolled natural gas production wells may not be transferred for domestic use, unless otherwise approved the Commission after notice and a hearing. Notice shall be given to all owner(s), as defined in Ark. Code Ann. § 15-72-102 (9), and all mineral owners in the leasehold upon which the well is located. Any person requesting a transfer of an uncontrolled natural gas production well shall file an application in accordance with General Rules A-2, A-3, and other applicable hearing procedures.

d) Domestic Use Transfer(s) prior to November 16, 2008.

Any natural gas production well transferred to a surface owner for use as a domestic natural gas supply well prior to November 16, 2008, shall no longer be subject to the regulatory oversight by the Commission as long the natural gas from the well is used only on the property where the well is located and that any natural gas production from the well is not sold.

(Source: 1992 rule book; amended November 16, 2008; amended May 18, 2012)

RULE B-12: REPEALED

Rule Repealed Effective November 11, 2007

RULE B-13: ORGANIZATION REPORTS

a) Every person or entity engaged in any operation or activity regulated by the Commission, shall file with the Commission an organization report on a form prescribed by the Director, prior to engaging in the operation or activity. At a minimum, the form shall include:

1) Name of person or entity and type of operation(s) being conducted;

2) An official mailing address to which all correspondence from the Commission is to be sent. If the official mailing address is to be sent to a registered agent for the person or entity, then the name of the registered agent must also be included;

3) A list of official telephone number(s), facsimile number(s), and e-mail address(es) for which contact by the Commission may be made;

4) The type of entity, and a list of all persons authorized to submit required forms, reports, and other documents for the entity;

5) A statement that the person or entity is authorized to conduct business within the State; and

6) Any other information deemed necessary by the Director.

b) Every person or entity shall file an updated organization report with the Commission on or before July 1st of every calendar year.

c) After any change occurs as to facts stated in the report filed, a supplementary report shall be filed with the Commission within thirty (30) days of any change.

(Source: 1992 rule book; amended January 22, 2009)

RULE B-14: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE B-15: CASING REQUIREMENTS

a. In all established fields, casing requirements shall be governed by the specific field rules for that field, and are not superceeded by this rule.

b. All fresh water sands shall be fully protected by the setting and cementing of surface casing to prevent the fresh water sands from becoming contaminated with oil, gas, or salt water. Surface casing shall be set and cement circulated to surface utilizing the pump and plug method. Cement shall be allowed to set a minimum of twelve (12) hours.

1) The minimum surface casing requirements for wildcat wells or wells not covered by field rules, in the counties of Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette, Miller, Nevada, Ouachita, and Union, are as follows:

TVD of well	Amount of Surface Casing
0′ - 3,000′	100′
3,001′- 4,000′	160′
4,001′- 5,000′	300′
5,001′- 6,500′	500′
6,501′- 7,500′	750′
7,501′- 8,500′	1,000′
8,501′-10,500′	1,250′
10,501′ & below	1,500′

2) The minimum surface casing requirements for wildcat wells or wells not covered by field rules, in the counties of Crawford, Franklin, Johnson, Logan, Madison, Pope, Scott, Sebastian, Washington, and Yell, are as follows:

TVD of Well	Amount of Surface Casing
0′- 1,500′	100′
1,501′- 3,000′	200′
3,001′- 6,500′	500′
6,501′-10,000′	800′
10,001′ & below	1,000′

3. The minimum surface casing requirements for wildcat wells or wells not covered by field rules, in the counties of Cleburne, Conway, Faulkner, Independence, Jackson, Searcy, Stone, Van Buren, and White, shall be to a depth of 500 feet or the top of the Paleozoic age rock sequence, whichever is greater.

4. The minimum surface casing requirements for wildcat wells or wells not covered by field rules, in the counties of Arkansas, Lonoke, Monroe, Prairie, and Woodruff, shall be to a depth of 1,250 feet.

5. The minimum surface casing requirements for wildcat wells or wells not covered by field rules, in the counties of Crittenden, Cross, Lee, Phillips and St. Francis, shall be to a depth of 2,000 feet.

c. A producing string of casing shall be set at least to the top of the producing formation and shall be cemented so that the calculated fill, after allowing for twenty-five percent excess, will be at least two hundred fifty feet above the top of any productive interval. Cementing shall be done by

the pump and plug method. Cement shall be allowed to set a minimum of twenty-four (24) hours before drilling the plug.

d. The Director may grant exceptions to the above requirements if conditions exist that require more than these requirements for the purpose of safety or for the protection of fresh water sands and oil or gas bearing sands or may establish minimum surface casing requirements in future producing areas not covered by this rule.*

*Director's Notice to Fayetteville Shale Operators – June 1, 2015 (Supersedes previous version of June 1, 2011). Unless an exception is granted, all operators of all wells spud after May 22, 2015, or permitted on or after June 1, 2015 in Cleburne, Conway, Faulkner, Independence, Jackson, Searcy, Stone, Van Buren, and White Counties, and Fayetteville Shale wells only in Pope County, shall comply with casing and cementing requirements based on the zone in which the well is located (please contact the El Dorado Regional office for the zone map). The well casing and cementing requirements are as follows:

1. Surface casing shall be set to a depth equal to 500 feet below the lowest ground surface elevation occurring within 1 mile of the proposed well, with a minimum of 1000 feet of surface casing required to be set and cemented to surface.

2. Production casing shall be set to at least the top of the producing formation, and cemented, such that the calculated top of cement (TOC), plus a twenty-five percent excess, shall be at a minimum of:

   a. 100 feet above the surface casing shoe in Zone 1;
   b. 500 feet below the surface casing shoe in Zone 2; and
   c. 1500 feet below the surface casing shoe in Zone 3.

3. If a gas bearing zone is encountered above the Fayetteville Shale in the subject well or in another well within a one (1) mile radius of the subject well, and the above cementing requirements do not result in at least 250 feet of cement placed above the shallow gas bearing zone, the TOC shall be increased to provide a minimum of 250 feet of cement above the shallower gas bearing zone. However, the additional cementing requirements in the subject well shall not result in the production casing TOC to extend more than 100 feet above the surface casing shoe inside the surface casing.

(Source: 1992 rule book; amended September 16, 2006)

RULE B-16: BLOW-OUT PREVENTION

All proper and necessary precautions shall be taken for keeping the well under control during drilling operations, including but not limited to the use of blow-out preventers and high pressure fittings attached to properly anchored and cemented casing strings or maintain mud-laden fluid of sufficient weight to provide proper well control. Blow-out preventers shall be tested at regular intervals to insure proper operation.

(Source: 1992 rule book; amended October 15, 2006)

RULE B-17: WELL DRILLING PITS AND COMPLETION PITS REQUIREMENTS

a) Applicability

This rule applies to all pits constructed during the drilling, completion and testing of a brine, oil, gas, or oil and gas production well, brine injection or disposal well, Class II Disposal Well, and Class II Commercial Disposal Well. Pits as used in context of this rule refer to the type pits as defined in subparagraph c) below.

b) Joint Enforcement

After the effective date of this rule, any Operator who constructs or operates a pit covered by this Rule, shall be subject to the specific enforcement provisions under the respective authorities of the Arkansas Oil and Gas Commission (AOGC) or the Arkansas Department of Environmental Quality (ADEQ). The regulation of the activities covered under this rule by AOGC and ADEQ shall be in accordance with a Memorandum of Agreement (MOA) between AOGC and ADEQ.

c) Definitions:

1) AOGC: Arkansas Oil and Gas Commission.

2) ADEQ: Arkansas Department of Environmental Quality.

3) APC&EC: Arkansas Pollution Control and Ecology Commission.

4) Closed Loop System: A system that uses a combination of solids control equipment incorporated in a series of steel tanks that eliminates the use of a Pit.

5) Completion Flow-Back Fluid: Any of a number of liquid and gaseous fluids or mixtures of fluids, chemicals and or solids that flow from a well and consisting of Drilling Fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which have been removed from the well bore during the initial completion of a well, but does not include Frac Flow-Back Fluid.

6) Cuttings: Fragments of rock which are a result of the cutting action of the drill bit on rock formations encountered in the well, which are transported to the surface by the Drilling Fluid.

7) Discharge: The release, overflow, leakage or seepage of any fluids covered by this Rule.

8) Drilling Fluid: Any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases, Cuttings and other solids) utilized during brine, oil, or gas drilling operations. Drilling Fluid is generally synonymous with drilling mud, which typically contains bentonitic clays, chemical additives, foaming agents, lubricants, emulsifiers and weighting materials, and which encompasses most muds used in drilling operations, especially muds that contain significant amounts of suspended solids, emulsified water or oil. Mud includes all types of Water-Based, Oil-Based and synthetic-based Drilling Fluids.

9) Director of the ADEQ: The Director of the Arkansas Department of Environmental Quality or his or her designated representative.

10) Director of AOGC: The Director of the Arkansas Oil and Gas Commission or his or her designated representative.

11) Ecologically Sensitive Waterbody (ESW): Waters that have been given the designated use of Ecologically Sensitive Waterbody by the Arkansas Pollution Control and Ecology Commission. This beneficial use identifies segments known to provide habitat within the existing range of threatened, endangered or endemic species of aquatic or semi-aquatic life forms.

12) Encountered Water: Water encountered during brine, oil, or gas drilling operations, which is of sufficient quantity to require disposal, and which is not Produced Water.

13) Exploration and Production Waste (E&P Waste): Wastes associated with the exploration, development and production of brine, oil, or gas and which are not regulated by the provisions of, and, therefore, exempt from the Federal Resource Conservation and Recovery Act, and may include, but are not limited to the following: salt water (produced brine or produced water); Oil-Based Drilling Fluids; Water-Based Drilling Fluids, Completion Flow-Back Fluid, Frac Flow-Back Fluid, Workover Flow-Back Fluid, Produced Water; rainwater from firewalls and Pits at drilling and production facilities; and other wastes not described above.

14) Extraordinary Resource Waters (ERW): Waters that have been given the designated use of Extraordinary Resource Waterbody by the Arkansas Pollution Control and Ecology Commission. This beneficial use is a combination of the chemical, physical and biological characteristics of a water body and its watershed which is characterized by scenic beauty, aesthetics, scientific values, broad scope recreation potential and intangible social values.

15) Frac Flow-Back Fluid: Fluids that consist of fresh water and solids such as sand or other proppant (resin or ceramic grains) or other additives that flow from a well following hydraulic fracturing of a well, until such time as the volume of fluid utilized for the hydraulic fracturing process in the well has been recovered.

16) Natural and Scenic Waterways (NSW): Waters that have been given the designated use of Natural and Scenic Waterways by the Arkansas Pollution Control and Ecology Commission. This beneficial use identifies segments which have been legislatively adopted into a state or federal system.

17) Nonhazardous Oilfield Wastes (NOW): Fluids to be used or reused in connection with activities associated with the exploration, development, and production of brine, oil, or gas and includes, but is not limited to, Drilling Fluids, completion fluids, surfactants, and chemicals used to detoxify brine, oil, or gas wastes.

18) Oil-Based Drilling Fluid: Drilling Fluid containing diesel or crude oil rather than fresh water as the main liquid phase of the drilling mud.

19) Operator: Any person who has the primary management and ultimate decision-making responsibility over the operation of a facility or activity. The Operator is responsible for ensuring compliance with all applicable rules and conditions.

20) Person: Natural person, corporation, organization, municipality, government or governmental subdivision or agency, public or private corporation, business trust, estate, trust, individual, partnership, association, or any other legal entity.

21) Pit: shall include:

A) Circulation Pit: A pit used during drilling where Drilling Fluids are circulated during drilling operations. The Circulation Pit may be part of the Mud Pit. Circulation Pits may also refer to a series of open, above-ground tanks, usually made of steel.

B) Completion Pit: A pit used for storage of Completion Flow-Back Fluid and Drilling Fluids or other materials which have been cleaned out of the well bore during the initial completion of a well. Circulation or Mud Pits may be used as a Completion Pits when drilling operations conclude.

C) Emergency Pit: A pit used for containing fluids at an operating well during an actual emergency and for a temporary period of time. Use of the Emergency Pit is necessitated due to unplanned operational issues, which may include but is not limited to, a temporary shutdown of a disposal well or fluid injection well or associated equipment, temporary overflow of saltwater storage tanks on a producing lease, gas flaring, cement circulation, or a producing well loading up with formation fluids.

D) Mud Pit: A pit or series of pits used during drilling where fluids are mixed and circulated during drilling operations. Mud Pits may also refer to a series of open, above-ground tanks, usually made of steel.

E) Reserve Pit: A pit not part of the active circulation system, used to store Drilling Fluids or to contain fluids generated during drilling operations. Such fluids would include, but not be limited to, Cuttings, Drilling Fluids, and Encountered Water.

F) Test Pit: A pit constructed for use during a well test.

G) Workover Pit: A pit used for storage of Completion Flow-Back Fluid, Workover Flow-Back Fluid and other materials which have been cleaned out of the well bore during any subsequent completion or re-completion.

22) Pollution: Such contamination or other alteration of the physical, chemical, or biological properties of any waters of the state, or such discharge of any liquid, gaseous, or solid substance in any waters of the state as will, or is likely to, render the waters harmful, detrimental, or injurious to public health, safety, or welfare; to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses; or to livestock, wild animals, birds, fish, or other aquatic life.

23) Produced Water: Water produced from any productive or potentially productive brine, oil, or gas producing interval in the well, which is not Completion Flow-Back Fluid, Frac Flow-Back Fluid, Workover Flow-Back Fluid, or Encountered Water.

24) Stormwater: Rainwater runoff, snow melt runoff, and surface runoff and drainage.

25) Water-Based Drilling Fluid: Drilling Fluid containing fresh waters rather than diesel or crude oil as the liquid component of the drilling mud.

26) Waters of the State: All streams, lakes, marshes, ponds, watercourses, waterways, wells, springs, irrigation systems, drainage systems, and all other bodies or accumulations of

water, surface and underground, natural or artificial, public or private, which are contained within, flow through, or border upon this state or any portion of the state.

27) Water Table: The surface between the zone of saturation and the zone of aeration and the surface of a body of unconfined ground water at which the pressure is equal to that of the atmosphere.

28) Workover Flow-Back Fluid: Any of a number of liquid and gaseous fluids and mixtures of fluids, chemicals and or solids consisting of Drilling Fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which are removed from the well bore during the subsequent or recompletion of a well.

d) Commencement of Construction Operations

The Operator shall notify the appropriate AOGC Regional Office, via mail, e-mail or fax, at least forty-eight (48) hours prior to the commencement of Pit construction operations. The Notice of Commencement (NOC) shall be on a form agreed upon by AOGC and ADEQ and shall include at a minimum (i) the Operator information (name, address, and emergency contact phone number), (ii) the location of the drill pad site (latitude and longitude in degrees, minutes, seconds, and County, Section, Range, and Township, including the 1/4 of the 1/4 position within the Section), (iii) the approximate size of the drill pad, (iv) the approximate distance to the nearest Waters of the State, (v) the type of fluid system and type of Drilling Fluids to be used, (vi) well name, (vii) nearest city/town, and (viii) the approximate date Pit construction operations shall commence. Upon receiving the Notice of Commencement, AOGC shall forward a copy to ADEQ, Arkansas Department of Health, and the County Judge of the county in which the pit is located. AOGC and ADEQ staff may conduct site inspections as deemed necessary.

e) Discharges Prohibited

The Discharge from a Pit or any activity associated with the drilling or completion of a well to any surface or ground waters or in a location where it is likely to cause pollution to any surface or groundwaters is prohibited. Such discharge may subject the Operator to ADEQ enforcement actions under the provisions of the Water and Air Pollution Control Act (Act 472 of 1949, as amended, A. C. A. § 8-4-101, et seq.) and enforcement actions of AOGC under Act 105 of 1939, as amended. Any Discharge must be reported within twenty-four (24) hours to the AOGC and ADEQ. Leakage from any Pit is considered an unauthorized Discharge.

f) Mud, Circulation and Reserve Pit Construction Requirements:

1) General Requirements:

A) Mud, Circulation and Reserve Pits constructed within the 100 year flood plain must be in accordance with any county or other local ordinance or requirement pertaining to the 100 year flood plain.

B) The location of all Mud, Circulation or Reserve Pits shall be chosen with reasonable consideration to maximizing the distance from surface waters. Mud, Circulation or Reserve Pit construction in streams, creeks, lakes, or any other water bodies is strictly prohibited.

C) Any Mud, Circulation or Reserve Pit construction in wetlands must receive appropriate prior authorization from the U.S. Army Corps of Engineers.

D) In areas other than jurisdictional wetlands referenced in subparagraph f) 1) C) above, where the water table is ten (10) feet or less below the ground surface, all Mud, Circulation or Reserve Pits shall be constructed above ground, or the Operator shall use a closed loop system.

2) Reserve Pit Requirements:

A) All Reserve Pits shall be constructed with a minimum of two (2) feet of freeboard, and shall be maintained to handle a storm event up to a 10-year, 24-hour storm event during the operation of the Reserve Pit. Reserve Pits constructed above ground utilizing bermed side walls, shall be constructed with a minimum of 2:1 (two feet horizontal to one foot vertical) side slope on both the interior and exterior walls. The top of the bermed pit walls must be a minimum of 2 feet wide.

B) All Reserve Pits shall be constructed with a liner using one of the following methods:

i) A synthetic liner of at least twenty (20) mils thickness, with a four (4) inch welded seam overlap, completely covering the Reserve Pit bottom and inside walls. Sand or sandy material must be placed below the liner if a rocky or uneven surface is encountered. The synthetic liner must be protected from deterioration, punctures and/or any activity which may damage the integrity of the synthetic liner.

ii) A compacted clay liner may be applied to the bottom and sides of the Reserve Pit to create an impervious/impermeable barrier. Construction of the Reserve Pit and compacted clay liner shall be in accordance with sound construction and engineering principles designed and constructed to prevent any leakage or seepage to Waters of the State, with due consideration given to the topography, Pit material composition, and availability of liner material(s). The clay used to construct the liner may be in situ or mixed with additional off-site materials, if the on-site clay is inadequate.

iii) Other materials or methods used for liner construction must be approved by both the Director of the ADEQ and the Director of the AOGC prior to use.

3) Mud and Circulation Pits:

A) Closed Loop Systems may be used for Mud and Circulation Pits, and must be maintained in a leak-free condition.

B) Earthen Mud and Circulation Pits shall be constructed with a minimum of two (2) feet of freeboard, and shall be maintained to handle a storm event up to a 10-year, 24-hour storm event during the operation of the Mud or Circulation Pit.

C) Earthen Mud and Circulation Pit liners shall be constructed using one of the following methods:

i) A synthetic liner of at least twenty (20) mils thickness, with a four (4) inch welded seam overlap, completely covering the Reserve Pit bottom

and inside walls. Sand or sandy material must be placed below the liner if a rocky or uneven surface is encountered. The synthetic liner must be protected from deterioration, punctures and/or any activity which may damage the integrity of the synthetic liner.

ii) Bentonite drilling mud from fresh Water-Based Drilling Fluids may be used on the bottom and sides of the earthen Mud or Circulation Pit to create an impervious/impermeable barrier. Application of the Mud or Circulation Pit bentonite drilling mud liner shall be in accordance with sound construction and standard industry practices designed and constructed to prevent any Discharge.

iii) A concrete liner may be applied to the bottom and sides of the earthen Mud or Circulation Pit to create an impervious/impermeable barrier. Construction of the Mud or Circulation Pit concrete liner shall be in accordance with sound construction and standard industry practices designed and constructed to prevent any Discharge.

D) Oil-Based Drilling Fluids shall not be placed in an earthen Mud or Circulation Pit unless the Pit is lined with a synthetic or concrete liner as prescribed in subparagraph f) 3) C) i) or iii) above.

E) If Oil-Based Drilling Fluids are to be used, and the location of the Mud or Circulation Pit is within 100 feet of a pond, lake, stream, ERW, ESW or NSW, the Operator is required to use a Closed Loop System.

g) Operating Requirements For Mud, Circulation or Reserve Pits:

1) No waste oil, hydraulic fluids, transmission fluids, trash or any other miscellaneous rig waste may be placed, stored or disposed into a Mud, Circulation, or Reserve Pit.

2) Produced Water, and Frac Flow-Back Fluid may not be placed, stored or disposed in a Mud, Circulation, or Reserve Pit, except that as part of a Frac Flow-Back Fluid recycling program, Frac Flow-Back Fluids, and upon approval of both AOGC and ADEQ Directors, Produced Water, may be temporarily placed or stored in a Reserve Pit, for a period not to exceed ninety (90) days per pit use for this purpose if:

A) The Reserve Pit is constructed with a clay liner as specified in subparagraph f) 2) B) ii) above and a synthetic liner of at least forty (40) mils thickness, or two (2) twenty (20) mils thickness synthetic liners, in addition to all other applicable Reserve Pit construction requirements as specified in subparagraph f) 2) above, and have a means to monitor between the synthetic liners (if two liners are utilized) and below the bottom of the lower most synthetic liner; and

B) The Operator requests approval from ADEQ in writing prior to the placement or storage of the Frac Flow-Back Fluid or approved Produced Water, in a Reserve Pit. Such request shall include the AOGC Well Permit Number, well names(s), description of the water to be stored, anticipated dates of use, volume of water to be stored or placed, detailed information on any proposed pipelines for the transfer Frac Flow-Back Fluids including a map showing proposed pipeline location for; and

C) No Frac Flow-Back Fluids or other fluids mixed with Frac Flow-Back Fluids temporally stored or placed in a Reserve Pit may be sent to any commercial land applications disposal facility or land applied onsite.

3) Water-Based Drilling Fluid, Stormwater, water from Waters of the State, or Encountered Water may be placed or stored in an earthen Mud, Circulation or Reserve Pit.

4) Mud, Circulation and Reserve Pits must be maintained in such a manner as to prohibit any Discharges. The Operator is required to maintain adequate storage capacity at all times.

5) Mud, Circulation and Reserve Pit levees or walls shall be protected and maintained at all times to prevent deterioration or discharge. In addition, Pit liners shall also be maintained and protected from deterioration or puncture causing discharge of fluids until such time that the Pit is emptied and closed.

6) Mud, Circulation and Reserve Pits shall contain only Drilling Fluids generated during the drilling of the well or wells at the drilling pad where the Pit is constructed, except that as part of a Frac Flow-Back Fluid recycling program a Reserve Pit, permitted in accordance with subparagraph g) 2) above, may temporarily contain Frac Flow-Back Fluids and upon approval by both AOGC and ADEQ Directors, Produced Water, which may be transferred to another drill pad Reserve Pit permitted in accordance with subparagraph g) 2) above. The transfer of Frac Flow-Back Fluids and approved Produced Water, via tank truck, shall be in accordance with General Rule E-3. If the transfer of Frac Flow-Back Fluids and approved Produced Water, is via pipeline, such pipeline shall be constructed and maintained in a leak-free condition and protected from deterioration, punctures and/or any activity which may damage the integrity of the pipeline. If the proposed pipeline will result in a stream crossing, a short term activity authorization shall be received from the ADEQ prior to construction. Any discharge from the pipeline shall be reported immediately to ADEQ.

7) In the event of an emergency and with prior approval from either the Director of ADEQ or the AOGC, the Reserve Pit may be used for temporary additional storage of Water-Based Drilling Fluids from another drilling pad location. In the event of an emergency, any request for approval must be submitted to both ADEQ and AOGC for review. ADEQ or AOGC will provide notice to each other at the time of the approval of any request made pursuant to this paragraph.

8) Except as specified in subparagraph i) 1), or in an emergency and with prior approval from the Director of the ADEQ hauling or transporting Drilling Fluids from a Pit to an off-site location, not located on a drilling pad, for additional storage is prohibited.

9) Oil-Based Drilling Fluids shall be segregated from Water-Based Drilling Fluids and other Drilling Fluids.

h) Fluid Disposal and Earthen Pit Closure Requirements for Water-Based Drilling Fluid and Encountered Water.

1) Water-Based Drilling Fluid, Stormwater, water from Waters of the State, or Encountered Water stored in the Pits shall be removed to the maximum extent practical using pumps or similar equipment at the time of Pit closure, and shall be disposed of in one of the following manners:

A) Land applied in accordance with an active ADEQ land application permit.

B) Disposed of fluid into approved NPDES or state permitted facility.

C) Injected via Class II wells permitted by AOGC.

D) Pumping the Water-Based Drilling Fluids back down the well bore of the well in accordance with AOGC requirements.

E) Water-Based Drilling Fluids exhibiting high viscosity to high solids concentration may be solidified or stabilized by combining with available native soils and buried in situ. The Operator is responsible for ensuring the native soils are properly mixed to prevent any discharge.

F) Transported by truck or by pipeline to a Reserve Pit, which is part of an approved Frac Flow-back Fluid recycle program.

G) By any other method as approved by ADEQ and AOGC.

2) The Operator shall take all reasonable measures to ensure that Drilling Fluid and Encountered Water that is removed from the well-site, are properly transported to and disposed of or recycled or reclaimed at an AOGC or ADEQ permitted site or facility, or a permitted site or facility outside of Arkansas.

3) Any synthetic liner used shall be removed to the fullest extent practicable and properly disposed or recycled.

4) The closed Pit shall be filled with native materials and covered with topsoil at depths consistent with adjoining onsite areas, with the contour mounded or sloped to discourage erosion and restored as close to the original contours as is practicable. Topsoil and native materials removed during Pit construction may be preserved and used during closure.

5) The oil & grease content of the material to be buried in situ shall be less than 3% by dry weight.

6) The pit and applicable portion of the drill pad not utilized for production purposes, shall be returned to grade, reclaimed and seeded within a reasonable amount of time not to exceed one hundred eighty days (180) days after the drilling or workover rig is removed from the site, or in the case of a multiple well drill pad, within 180 days after the drilling or workover rig utilized for the last well to be drilled from the drill pad is removed, during which period the reserve pit shall be maintained in accordance with the provisions of this rule. An extension of the time to close the pit may be granted upon approval of both AOGC and ADEQ. Vegetative coverage of 75%, or equivalent to the surrounding landscape, whichever is less, shall be obtained within six (6) months of Pit closure. Until vegetation is established, the Operator is responsible for maintaining a stormwater erosion and sediment control plan.

7) The Operator shall submit the Notice of Pit closure to AOGC signed by the Operator within 30 days after Pit closure has been completed. AOGC shall forward a copy to ADEQ.

i) Fluid Disposal and Earthen Pit Closure Requirements for Oil-Based Drilling Fluids.

1) Oil-Based Drilling Fluids shall be removed from the Pit and hauled to a permitted Class 1 (as defined by APC&EC Rule No. 22) landfill for disposal or be transferred to above ground tanks for re-use at another well location, or other disposal methods or uses of Oil-Based Drilling Fluids as approved by the ADEQ. The Operator shall inform the AOGC of the location of the disposal or transfer of the Oil-Based Drilling Fluid. AOGC shall forward a copy to ADEQ.

2) If an Oil-Based Drilling Fluid other than diesel is used as the base, additional analytical or disposal requirements may be required, which shall require prior notification and approval by ADEQ.

3) Any synthetic liner used shall be removed to the fullest extent practicable and properly disposed or recycled.

4) The closed Pit shall be filled with native materials and covered with topsoil at depths consistent with adjoining onsite areas, with the contour mounded or sloped to discourage erosion and restored as close to the original contours as is practicable. Topsoil and native materials removed during Pit construction may be preserved and used during closure.

5) The area shall be returned to grade, reclaimed and seeded within a reasonable amount of time not to exceed one hundred eighty days (180) days after the drilling rig is removed from the site. Vegetative coverage of 75%, or equivalent to the surrounding landscape, whichever is less, shall be obtained within six (6) months of closure. Until vegetation is established, the Operator is responsible for maintaining a stormwater erosion and sediment control plan.

6) The Operator shall submit the Notice of Pit closure to AOGC signed by the Operator within 30 days after Pit closure has been completed. AOGC shall forward a copy to ADEQ.

j) Requirements for Workover Pits, Emergency Pits and Test Pits

1) No Produced Water, Workover Flow-Back Water, waste oil, or any other Nonhazardous Oilfield Wastes (NOW) shall be placed in a Workover, Emergency, or Test Pit, unless the Pit is lined in accordance with subparagraph f) 2) B) above.

2) All Workover, Emergency, or Test Pits shall be closed within thirty (30) days after the associated workover, emergency, or test ceases. Any Workover, Emergency, or Test Pit shall be closed in accordance with the requirements of subparagraph h) above.

k) Other drilling mud systems not specifically authorized by this Rule shall require prior notification and approval by the Director of the AOGC and the Director of ADEQ.

l) Stormwater Erosion and Sediment Controls

1) The Operator shall prepare a stormwater erosion and sediment control plan for the well site covered by this rule. The plan shall be prepared in accordance with proven and accepted engineering practices. The plan shall describe and ensure the implementation of both erosion and sediment control practices which are to be used to reduce pollutants in stormwater discharges associated with the well pad and access roads to minimize erosion and reduce the sediments which may enter waters of the state and assure compliance with any applicable Water Quality Standards (WQS). Facilities shall implement the

provisions of the plan required under this rule. The Operator shall provide upon request by the ADEQ or AOGC a copy of the stormwater erosion and sediment control plan.

2) In lieu of a stormwater erosion and sediment control plan as required above, the Operator may use a guidance document that provides Operators the appropriate erosion and sediment controls based upon geographic region, terrain, and distance to adjacent water bodies previously submitted and approved by ADEQ.

3) Any facility that potentially discharges stormwater runoff to a water body listed for siltation pursuant to Section 303(d) of the Clean Water Act, or an ERW, ESW or a NSW shall have a site specific stormwater erosion and sediment control plan prepared and certified by a registered professional engineer, and such plan shall incorporate best management practices to provide reductions of the listed pollutants to the extent reasonably feasible. The 303(d) list, and the location of ERW, ESW, and NSW waters are available from ADEQ's website at the following address: http://www.adeq.state.ar.us/water/.

(Source: Original Rule Repealed October 15, 2006; New Rule Effective October 28, 2010 – Implementation October 1, 2011; amended April 1, 2012; amended November 19, 2018)

RULE B-18: WELLHEAD FITTINGS

Christmas tree fittings or wellhead connections shall have a working pressure or a test pressure in keeping with the expected depth of the well.

(Source: 1992 rule book)

RULE B-19: REQUIREMENTS FOR WELL COMPLETION UTILIZING FRACTURE STIMULATION

a) Definitions

1) "ADEQ" means the Arkansas Department of Environmental Quality.

2) "Additive" means any substance or combination of substances, including proppant, having a specified purpose that is combined with a Hydraulic Fracturing Fluid.

3) "AOGC" means the Arkansas Oil and Gas Commission.

4) "Chemical Abstract Service" or "CAS" means the chemical registry that is the authoritative collection of disclosed chemical substance information.

5) "Chemical Constituent" means a discrete chemical with its own specific name or identity (such as, but not necessarily, a CAS number) that is contained in an additive.

6) "Chemical Family" means a group of elements in the Periodic Table or, more commonly, compounds that share certain physical and chemical characteristics and have a common name.

7) "Hydraulic Fracturing Fluid" means the base fluid type utilized in a particular Hydraulic Fracturing Treatment.

8) "Hydraulic Fracturing Treatment" means stimulating a well by the application of Hydraulic Fracturing Fluids and Additives with force in order to create artificial fractures in the formation for the purpose of improving the capacity to produce hydrocarbons.

9) "RCRA" means Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et. seq.

b) The provisions of this Rule shall apply to all new horizontal wells and all vertical wells in which the amount of Hydraulic Fracturing Fluid used during the Hydraulic Fracturing Treatment of the well exceeds 10,000 barrels Hydraulic Fracturing Fluid and for which an initial drilling permit was issued on or after January 15, 2011.

c) Persons applying for a permit to drill shall indicate on the initial drilling application the intent to perform Hydraulic Fracturing Treatment operations and provide the information required in accordance with subparagraph d) below. If the intent to fracture stimulate a well was not provided at the time of the initial drilling application, a Permit Holder desiring to perform Hydraulic Fracturing Treatment operations shall send the information required in accordance with subparagraph d) below via e-mail, fax or mail to the AOGC office where the initial drilling permit was issued, prior to commencement of Hydraulic Fracturing Treatment operations.

d) The application described in subparagraph c) above shall include:

1) The following information on the proposed casing program, demonstrating that the well will have steel alloy casing designed to withstand the anticipated maximum pressures to which the casing will be subjected in the well:

A) Whether the well will be a vertical well, a directional well, or a horizontal well; and

B) The estimated true vertical and measured production casing setting depths; and

C) The casing grade and minimum internal yield pressure for the production casing proposed to be used in the well.

2) The following information demonstrating that the well will have sufficient cement volume and integrity to prohibit movement of fracture fluids up-hole into the various casing or well bore annuli:

A) The proposed cement formulation(s)' minimum compressive strength; and

B) The estimated top of cement for the production casing string.

3) The anticipated surface treating pressure range for the proposed Hydraulic Fracturing Treatment program. The production casing described in subparagraph d) 1) above shall be sufficient to contain the maximum anticipated treating pressure of the Hydraulic Fracturing Treatment, which shall not exceed 80% of the minimum internal yield pressure for such production casing.

e) Surface casing in the well in which the proposed Hydraulic Fracturing Treatment will occur shall be set, and cemented to the surface, to a depth in accordance with General Rule B-15, and have sufficient internal yield pressure to withstand the anticipated maximum pressures to which the casing will be subjected in the well. If during the drilling of the surface portion of the well, and prior to setting surface casing, a freshwater flow is encountered, or the Permit Holder gains knowledge that freshwater will be encountered, from a deeper zone than was specified on the permit to drill, surface casing shall be set and cemented at least one hundred (100) feet below the deepest encountered freshwater zone.

f) If during the setting and cementing of production and/or any intermediate casings the cement program does not occur as submitted in accordance with this Rule, and would cause a reasonably prudent Permit Holder to question the integrity of the cementing program with respect to isolating the zone of Hydraulic Fracturing Treatment from movement of fracture fluids up-hole into the various casing or well bore annuli, the Permit Holder shall immediately notify the Director, or his designee, in writing as soon as practicable, but not more than twenty-four (24) hours after the event. In reviewing the report, the Director, or his designee, may require a bond log or other cement evaluation tool to document cement integrity and require additional cementing operations or other appropriate well workover efforts necessary to correct any cement deficiencies prior to initiating any Hydraulic Fracturing Treatments in the well.

g) The Permit Holder shall notify the Director or his designee via e-mail, fax or other approved method, a minimum of forty-eight (48) hours prior to commencement of a Hydraulic Fracturing Treatment on a well. If the Permit Holder cannot provide notice a minimum of forty-eight (48) hours prior to commencement, the Permit Holder shall provide a written explanation as to why the notice could not be provided, and the Permit Holder shall provide notice in the manner described above as soon as the Permit Holder is aware that a Hydraulic Fracturing Treatment has been scheduled.

h) The Permit Holder shall monitor all casing annuli that would be diagnostic as to a potential loss of well bore integrity during the Hydraulic Fracturing Treatment. The Permit Holder shall establish methods to timely relieve any excessive pressures to avoid the loss of surface casing integrity.

i) The Permit Holder must provide written notice to the Director, or his designee, of (i) any change in surface casing annulus pressure that would indicate movement of fluids into the annulus, or (ii) a pressure that exceeds the rated minimum internal yield pressure on any casing string in communication with the Hydraulic Fracturing Treatment. This written notice shall be delivered as soon as possible after the event, but not more than twenty-four (24) hours after the event. Following notification and any request for additional information, the Director, or his designee, may request additional documentation or well tests to determine if the Hydraulic Fracturing Treatment potentially endangered any freshwater zones. The Director, or his designee, may require appropriate additional cementing operations, or other well workover efforts to correct any well failure. Pending completion of required operations or efforts, the Director, or his designee, may order the cessation of further Hydraulic Fracturing Treatment and/or other well operations. The Director shall report any such incident to the Commission at its next regularly scheduled hearing, and the Commission may take such further action as it deems necessary and appropriate under the circumstances.

j) All non-exempt RCRA materials and fluids used on-site in the Hydraulic Fracturing Treatment shall be handled and stored in accordance with ADEQ requirements and any spills of these materials and fluids on-site or off-site shall be reported to ADEQ in accordance with applicable ADEQ requirements. All RCRA exempt materials and fluids used on-site in the Hydraulic Fracturing Treatment shall be contained in leak free tanks or other containment vessels. Any on-site spill of these materials or fluids shall be immediately contained, remediation efforts shall be commenced as soon as practical, and the incident shall be reported to the Director, or his designee, within twenty-four (24) hours.

k) All Hydraulic Fracturing Treatment flow back fluids shall be handled, transported, stored, disposed, or recycled for re-use in accordance with the applicable provisions of General Rule B-17, General Rule E-3 and General Rule H-1, H-2 and H-3.

l) Following completion of the Hydraulic Fracturing Treatment, the Permit Holder shall, for purposes of disclosure, report detailed information to the Director, or his designee, of the Hydraulic Fracturing Treatment in the manner customarily reported or presented to the Permit Holder, within the time period specified in General Rule B-5, as follows:

1) The maximum pump pressure measured at the surface during each stage of the Hydraulic Fracturing Treatment; and

2) The types and volumes of the Hydraulic Fracturing–Fluid and proppant used for each stage of the Hydraulic Fracturing Treatment; and

3) The calculated fracture height as designed to be achieved during the Hydraulic Fracturing Treatment and the estimated TVD to the top of the fracture; and

4) A list of all Additives used during the Hydraulic Fracturing Treatment specified by general type, such as acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, scale inhibitor, proppant and surfactant; and

5) The names of all specific Additives for each Additive type, specified in subparagraph l) 4) above, utilized during the Hydraulic Fracturing Treatment and the actual rate or concentration for each such Additive expressed as pounds per thousand gallons or gallons per thousand gallons additionally, the Additives are to be expressed as a percent by volume of the total Hydraulic Fracturing Fluids and Additives; and

6) The Permit Holder shall supply field service company tickets (excluding pricing) and reports regarding the Hydraulic Fracturing Treatment, as used in the normal course of business to satisfy some or all of the foregoing information requirements; and

7) The Permit Holder shall supply all information received from the person performing the Hydraulic Fracturing Treatment specified in subparagraph m) 4) below.

8) If the Permit Holder causes any Additives to be utilized during the Hydraulic Fracturing Treatment not otherwise disclosed by the person performing the Hydraulic Fracturing Treatment, the Permit Holder shall disclose a list of all Chemical Constituents and associated CAS numbers contained in all such Additives; provided, however, in those limited situations where the specific identity of any such Chemical Constituent and associated CAS number is entitled to be withheld as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042, the Permit Holder shall (i) submit to the Director a claim of entitlement to have the identity of such Chemical Constituent withheld as a trade secret, and (ii) provide the Director with the Chemical Family associated with such Chemical Constituent. The identity of any Chemical Constituent that qualifies as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042 shall be held confidential by the Director.

9) Nothing in subparagraph l) 8) above shall authorize any person to withhold information which is required by state or federal law to be provided to a health care professional, a doctor, or a nurse. All information required by a health care professional, a doctor, or a nurse shall be supplied, immediately upon request, by the person performing the Hydraulic Fracturing Treatment, directly to the requesting health care professional, doctor, or nurse, including the percent by volume of the Chemical Constituents (and associated CAS numbers) of the total Hydraulic Fracturing Fluids and Additives.

m) Any person performing Hydraulic Fracturing Treatments within the State of Arkansas shall:

1) Be authorized to do business in the State of Arkansas; and

2) Be required to file Organization Reports in accordance with General Rule B-13, and include the length of time the entity has been in the business of performing Hydraulic Fracturing Treatments; and

3) Disclose to the Director, or his designee, and maintain separate master lists of:

A) All Hydraulic Fracturing Fluids to be utilized during any Hydraulic Fracturing Treatment within the State of Arkansas; and

B) All Additives to be utilized during any Hydraulic Fracturing Treatment within the State of Arkansas; and

C) All Chemical Constituents and associated CAS numbers to be utilized in any Hydraulic Fracturing Treatment within the State of Arkansas; provided, however, in those limited situations where the specific identity of any such Chemical

Constituent and associated CAS number is entitled to be withheld as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042, the person performing the Hydraulic Fracturing Treatment shall (i) submit to the Director a claim of entitlement to have the identity of such Chemical Constituent withheld as a trade secret, and (ii) provide the Director with the Chemical Family associated with such Chemical Constituent. The identity of any Chemical Constituent that qualifies as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042 shall be held confidential by the Director; and

4) Provide to the Permit Holder for each well that such person performs a Hydraulic Fracturing Treatment, lists of:

A) The Hydraulic Fracturing Fluids utilized during the Hydraulic Fracturing Treatment; and

B) The Additives utilized during the Hydraulic Fracturing Treatment, and the actual rate or concentration for each such Additive utilized, expressed as pounds per thousand gallons or gallons per thousand gallons; additionally, the Additives are to be expressed as percent by volume of the total Hydraulic Fracturing Fluids and Additives, so that the Permit Holder may comply with its obligations under subparagraph l) above; and

C) All Chemical Constituents and associated CAS numbers utilized during the Hydraulic Fracturing Treatment; unless the specific identity of any such Chemical Constituent and associated CAS number is entitled to be withheld as a trade secret in accordance with subparagraph m) 3) c) above.

5) Nothing in subparagraphs m) 3) c) or l) 4) c) above shall authorize any person to withhold information which is required by state or federal law to be provided to a health care professional, a doctor, or a nurse. All information required by a health care professional, a doctor, or a nurse shall be supplied, immediately upon request, by the person performing the Hydraulic Fracturing Treatment, directly to the requesting health care professional, doctor, or nurse, including the percent by volume of the Chemical Constituents (and associated CAS numbers) of the total Hydraulic Fracturing Fluids and Additives.

n) No Permit Holder shall utilize the services of another person to perform a Hydraulic Fracturing Treatment unless the person performing a Hydraulic Fracturing Treatment is in compliance with subparagraph m) above.

(Source: Original Rule Repealed October 15, 2006; New Rule Effective January 15, 2011; Amended February 08, 2013; Amended July 15, 2017)

RULE B-20: REPEALED

Rule Repealed Effective October 15, 2006

RULE B-21: REPEALED

Rule Repealed Effective October 15, 2006

RULE B-22: REPEALED

Rule Repealed Effective November 11, 2007

RULE B-23: TUBING

a) All oil wells shall be equipped with, and produced through tubing. Bottom of tubing on flowing wells shall not be higher than top of producing interval. If tubing is perforated, the perforations shall not extend above the top of the producing interval.

b) All dry gas wells are not required to produce through tubing, provided surface casing has been set in the well in accordance with applicable rules. If multiple gas zones are produced in the well, authority to commingle in accordance with General Rule D-18 shall be required.

(Source: 1992 rule book; amended October 15, 2006)

RULE B-24: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE B-25: REPEALED

Rule Repealed Effective November 11, 2007

RULE B-26: GENERAL LEASE OPERATING REQUIREMENTS

a) Definitions for purposes of this rule

1) "Crude Oil Tank Battery" means crude oil storage tanks and other vessels commonly used in the production and temporary storage of crude oil.

2) "DEQ" means the Division of Environmental Quality.

3) "Director" means the Arkansas Oil and Gas Commission Director of Production and Conservation.

4) "EPA" means the United States Environmental Protection Agency

5) "Gas Well Produced Fluids Storage Tanks" means tanks or other vessels commonly used for the temporary storage of fluids, produced with natural gas, prior to disposal.

6) "Lease" means a tract of land under agreement by an owner or person, for the purpose of producing oil and or gas and allocating that production for himself or the owners of the oil and gas rights under that tract of land.

7) "Permit Holder" shall mean the operator or person, who is duly authorized to develop a lease or unit as owner or through agreement and has the right to drill and produce from any field or reservoir and to appropriate the production for himself or others.

8) "Produced Fluids" shall mean those fluids produced or generated during the crude oil production and separation process and shall include crude oil, crude oil bottom sediment and shall include all waters regardless of chloride content associated with production of oil and or gas.

10) 'Oil Well Produced Fluids Storage Tanks" means tanks or other vessels commonly used for the temporary storage of fluids produced with crude oil prior to disposal.

11) 'Oil Well Produced Fluids Storage Tanks" means tanks or other vessels commonly used for the temporary storage of fluids produced with crude oil prior to disposal.

12) "RCRA" means Subtitle C of the Federal Resource Conservation Recovery Act of 1976.

13) "USDW" means Underground Source of Drinking Water which is defined as an aquifer or its portion which:

A) supplies any public water system; or

B) contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 mg/l total dissolved solids; and

C) Which is not an exempted aquifer (see 40 CFR).

b) Well Identification

1) Each oil and or gas well shall have a legible sign placed at the well showing the Permit Holder and the well name and number as shown on the permit as listed in the

Commission records. If the lease is a single well lease, the well sign may be placed at the associated tank battery or lease entrance.

2) Every entrance from a public road to north Arkansas gas well sites shall have a legible sign placed at that entrance. The sign shall show the name of the Permit Holder, a list of all wells accessed by that entrance, the section, township and range, and a telephone number at which the Permit Holder or his authorized agent can be reached during an emergency.

3) For any newly drilled well, the required sign shall be posted within 45 days after cessation of drilling operations.

4) Any changes or corrections in the well information, required to be posted in accordance with this rule, shall be made to the well signs within sixty (60) days after the change occurs, or in the case of a transfer of well ownership, within sixty (60) days after the effective date of the transfer in the Commission records. All prior signs, if not correct, shall be removed.

c) Crude Oil Tank Batteries and Oil Well Produced Fluids Storage Tanks

1) All existing and newly constructed Crude Oil Tank Batteries and Oil Well Produced Fluids Storage Tanks shall be registered with the Commission and assigned a Commission registration number. Registration shall be reported to the Commission utilizing information as reported on the existing AOGC Form 6 Monthly Producers Report.

2) All Crude Oil Tank Battery and Oil Well Produced Fluids Storage Tanks registrations, shall be transferred, at the time of associated well transfers, utilizing the approved notice of well transfer forms filed with the Commission.

3) Each Crude Oil Tank Battery and Oil Well Produced Fluids Storage Tanks shall have a legible sign in a conspicuous place on or near the near the crude oil storage tank(s). The sign shall show the name of the Permit Holder who holds the Commission permit to operate the lease or unit, the lease name, the section, township and range, and a telephone number at which the Permit Holder or his authorized agent can be reached during an emergency.

4) All Crude Oil Tank Batteries and Oil Well Produced Fluids Storage Tanks shall be surrounded by containment dikes or other containment structures as may be appropriate under the circumstances, as approved by the Director. All containment dikes or other approved structures shall be constructed or installed in accordance with sub-paragraph (e) below.

5) All Crude Oil Tank Batteries and Oil Well Produced Fluids Storage Tanks, constructed after the effective date of this rule, shall not be located:

A) within 200 feet of an existing occupied habitable dwelling, unless the current owner of the structure has provided a written waiver consenting to the construction closer than 200 feet, in which case the tank battery shall be completely fenced to prevent unauthorized access; however, in no event may a tank battery may be constructed closer that 100 feet to an existing habitable dwelling; or

B) within 300 feet of a school, hospital or other type of public use building as defined in Arkansas Fire Prevention Code Section 3406.3.1.3.1; or

C) within 300 feet of a stream or river designated as an Extraordinary Resource Water (ERW), Natural and Scenic Waterways or Ecological Sensitive Waterbodies as defined by APC&E Rule 2, or within 200 feet of other streams, waterways, rivers, ponds, lakes, wetlands (unless approved by other appropriate governmental agencies), or other bodies of water (as indicated by a blueline designation on a 7.5 minute USGS Topographic Map), unless the Permit Holder utilizes additional containment measures other than the required containment specified in sub-paragraph (e) below, as approved by the Director.

6) All Crude Oil Tank Batteries and Oil Well Produced Fluids Storage Tanks or any part of such tanks shall not be buried below the ground surface.

7) All Crude Oil Tank Batteries and Oil Well Produced Fluids Storage tanks shall be maintained in a leak-free condition.

8) All open top tanks shall be covered with bird netting, or other system designed to keep birds and flying mammals from landing in the tank.

d) Gas Well Produced Fluids Storage Tanks

1) Tanks or any part of such tanks shall not be buried below the ground surface.

2) All tanks shall be maintained in a leak-free condition.

3) All open top tanks shall be covered with bird netting, or other system designed to keep birds and flying mammals from landing in the tank.

4) Tanks constructed after the effective date of this rule, shall not be located:

A) within 200 feet of an existing occupied habitable dwelling, unless the current owner of the structure has provided a written waiver consenting to the construction closer than 200 feet, in which case the tank battery shall be completely fenced to prevent unauthorized access; however, in no event may a tank battery may be constructed closer that 100 feet to an existing habitable dwelling; or

B) within 300 feet of a school, hospital or other type of public use building as defined in Arkansas Fire Prevention Code Section 3406.3.1.3.1; or

C) within 300 feet of a stream or river designated as an Extraordinary Resource Water (ERW), Natural and Scenic Waterways or Ecological Sensitive Waterbodies as defined by APC&E Rule 2, or within 200 feet of other streams, waterways, rivers, ponds, lakes, wetlands (unless approved by other appropriate governmental agencies), or other bodies of water (as indicated by a blueline designation on a 7.5 minute USGS Topographic Map), unless the Permit Holder utilizes additional containment measures other than the required containment specified in sub-paragraph (e) below, as approved by the Director.

5) All tanks containing produced fluids or equipped to receive produced fluids shall be surrounded by containment dikes or other containment structures as may be appropriate

under the circumstances, as approved by the Director. All containment dikes or other approved structures shall be constructed or installed in accordance with sub-paragraph (e) below.

e) Containment Dikes or Other Containment Structures

1) All Crude Oil Tank Batteries, Oil Well Produced Fluids Storage Tanks and Gas Well Produced Fluids Storage Tanks shall be surrounded by containment dikes or such other structure as may be appropriate under the circumstances, as approved by the Director to prevent waste, protect life, health or property, unless an exception is granted by the Commission following notice and hearing.

2) Required containment dikes or other approved structures shall be designed to have a capacity of at least 1½ times the largest tank the containment dike or approved structure surrounds.

3) The natural or man-made material utilized for the construction of the required containment dikes or other approved structures and the natural or man-made material used to line the bottom of the containment area shall be sufficiently impervious so as to contain fluids and resist erosion.

4) Vegetation on the top and outside surface of containment structures shall be properly maintained so as to not pose a fire hazard.

5) The area within the containment dike or other approved containment structure shall be kept free of excessive vegetation, stormwater, produced fluids, other oil and gas field related debris, general trash, or any flammable material. Drain lines installed through the firewall, for the purpose of draining stormwater, shall have a valve installed which shall remain closed and capped when not in use. Any fluids collected, spilled or discharged within such containment structures shall be removed as soon as practical, using the following proper disposal methods:

A) Stormwater, which has not been mixed with non-exempt RCRA waste as defined by the EPA, may be drained from the containment structure provided the following conditions are met:

i) the chloride content shall not exceed applicable state water quality standards.

ii) there must be no visible evidence of hydrocarbons or hydrocarbon sheen present;

iii) the discharge shall only take place during daylight hours;

iv) a representative of the Permit Holder must be present during discharge, unless otherwise approved by the Director; and

v) the Permit Holder shall maintain a record of each stormwater discharge, occurring in the previous 6 month period, and which shall be available for review upon request by Commission staff. The record shall indicate the location, quantity, chloride content, presence of any hydrocarbons (sheen), and date of discharge.

B) Produced fluids which have not been mixed with non-exempt RCRA waste as defined by the USEPA, may be recycled through the production equipment or removed from the containment structure and disposed in a properly permitted Class II UIC Well.

C) All stormwater and produced fluids which have been mixed with non-exempt RCRA waste as defined by the USEPA shall be removed and disposed in accordance with applicable Pollution Control and Ecology Commission rules, as administered by DEQ.

D) Crude oil bottom sediments (BS&W) may be:

i) applied on oil field lease roads under the following conditions:

a) application shall be in such a manner as to avoid runoff onto immediately adjacent lands or into Waters of the State; and

b) immediately following completion of the application, all liquid fractions shall be immediately incorporated into the road bed with no visible free-standing oil; and

c) no lease road shall be oiled more than twice a year; and

d) no lease road shall be oiled during precipitation events; and

e) the applied BS&W shall not have a produced water content greater than ten percent (10%) free water by volume; or

ii) injected into an inactive oil and gas production well:

a) which has been equipped with tubing and packer, for the purpose of said injection, the packer to be set within the production casing, at least fifty (50) feet below the top of the production casing cement, but no less than five hundred (500) feet below the base of the deepest USDW, and

b) injection of the BS&W shall not exceed 45 days, after which time the well shall be immediately plugged in accordance with General Rule B-8,and

c) if the Director determines through field observations that the injection activities are endangering the USDW, the injection activities shall cease until the condition is corrected.

6) Any residual produced fluids remaining within the containment dike, after removal, as required in subsection (e) (5) above, shall be remediated in place in accordance with General Rule B-34.

7) Any spill, leak or discharge of produced fluids escaping from a containment dike shall be reported and remediated in accordance with General Rule B-34.

8) When a Crude Oil Tank Battery, Oil Well Produced Fluids Storage Tanks, or Gas Well Produced Fluids Storage Tank or a gas well separator is removed, the Permit Holder shall

remove all above ground piping and flowlines coming into said tanks or separator and cap all below ground piping and flowlines, level and grade soil portion of the containment dikes, remove from site all non-soil containment structure construction material, and remediate all hydrocarbon contaminated soil at tank or separator site in accordance with General Rule B-34.

f) Liquid Hydrocarbon Flowlines and Produced Fluid Flowlines

1) All flowlines used in the production of liquid hydrocarbons, constructed after the effective date of this rule, shall be buried at least twenty-four (24) inches below the ground surface. Flowlines may be exempt from these burial requirements upon approval of the Director, in the following circumstances:

A) the topographical features, land uses or ground conditions prevent the efficient burial of flowlines; or

B) the suspected presence of numerous old abandoned flowlines, in old producing fields, render the burial of new lines impractical or which will significantly increase the likelihood of causing the discharge of crude oil from the old lines; or

C) the terms of the oil and gas lease or surface owner agreement, prohibit the burial of flowlines; or

D) the flowlines are installed or placed within the lease road right of way; or

E) the flowlines from the well to the tank battery are entirely within the confines of the original drilling location.

2) All flowlines which cross and are not buried under natural drainage features such as creeks, streams, rivers or intermittent streams or ravines shall be constructed in such fashion as to bridge the drainage feature to protect the flowlines from damage due to lack of adequate support, resulting in potential discharge and violation of the state water quality standards.

3) The Director shall have the authority to require active flowlines existing on the effective date of this rule to be replaced, buried or constructed in accordance with subsection (2) above or to require the visible aboveground inactive or abandoned portions of those abandoned flowlines to be removed and the open ends sealed, if the Director finds, based on field observation, that the flowlines constitute a hazard to public safety or can reasonably be expected to cause damage to the environment through leaks, spills or discharges.

4) No flowlines transporting produced water shall have an outlet valve installed for the purpose of discharging produced water between the place or well of origin and the authorized storage or disposal point. A specialized valve, installed for the purpose of venting trapped air, following flowline maintenance is permissible.

5) Any spill, leak or discharge from a flowline shall be reported and remediated in accordance with General Rule B-34.

g) Natural gas production lines and gathering lines shall be installed and operated in accordance with General Rule D-17 – General Rule Relative to Establishing An Effective And Efficient

Procedure For The Regulation Of Production Field Lines For Natural Gas As Well As Safety Standards or other applicable Commission rules.

h) Power Lines

1) All power lines installed after the effective date of this rule, shall be installed in such a manner as to prevent contact by vehicle or pedestrian travel.

2) The Director shall have the authority to require power lines existing on the effective date of this rule, to be in compliance with sub-paragraph (h) (1) above, if the Director finds, based on field observation, that the power lines constitute a hazard to public safety.

i) Equipment Use and Storage

1) All well head areas shall be kept free of excessive vegetation.

2) All production equipment, including but not limited to separators, heater treaters, piping, compressors, injection pumps, and chemical containers, shall be kept free of vegetation and maintained at all times in a safe and good working condition.

3) Used refined oil from any production equipment such as pumpjacks, injection pumps and compressors shall not be improperly disposed or placed in storage tanks containing produced water. All used refined oil shall be disposed in accordance with Arkansas Pollution Control and Ecology Commission Rule 23, Section 279.

4) Excess usable or operable production equipment, not integrally related to production activities on the lease, established drilling unit, or other unitized production area shall not be stored on any surface property unless written consent from the current surface owner where the production equipment is located, has been granted to the Permit Holder to store such equipment, unless the equipment has been designated by the Permit Holder to be used in the future on that lease, established drilling unit, or other unitized production area and the equipment and storage area, which shall be limited to an area in close proximity to existing well site(s) or production area(s), and are maintained and kept free of excessive vegetation.

5) Other trash and debris, including but not limited to, abandoned, unusable or unrepairable, junk tanks, treaters, tubulars, injection pumps, pump jacks, concrete, above ground piping and flowlines, and any other general junk equipment or machinery shall not be stored on any surface property except that owned by the Permit Holder. Removed trash and debris shall be disposed in accordance with applicable DEQ or other state agency rules.

j) Production Pits

1) "Production Pit", as used in this Section, is an earthen surface impoundment, whether a man-made excavation or a diked area which was or currently is used for temporary storage of produced fluids prior to disposal.

2) Construction of production pits, other than those pits previously authorized by Commission Orders are prohibited.

3) All other production pits in existence as of the effective date of this rule shall cease to be used on the effective date of this rule and closed within 90 days after the effective date of

this rule in a manner prescribed by the Commission and in accordance with all applicable state laws and rules, unless exempted in accordance with subsection (4) below.

4) Any production pit in existence as of the effective date of this rule, may not be subject to closure in accordance with subsection (j) (3) above if:

A) the pit is no longer used for temporary storage of produced fluids; and

B) the water quality in the pit is less than 1500 TDS with no visible sheen of oil; and

C) a written, notarized authorization from the current surface owner has been received by the Director requesting the pit not be closed and demonstrating an acceptable alternative use for the pit; and

D) in determining not to require the pit be closed, the Director shall:

i) review the current location of the pit relative to any ongoing production operations in the area; and

ii) review the proposed alternative use relative to public health and safety considerations and potential use for agricultural, recreational or wildlife habitat purposes.

E) If the Director determines, based on a review of the information submitted by the operator and surface owner, the pit is not exempted, the pit shall be closed, within six (6) months, by the operator, in accordance with subsection (3) above.

k) Leaking Permitted Well

Where any oil and gas reservoir fluids or salt waters or other produced fluids are potentially leaking into the USDW as determined by geologic and field investigation or are leaking onto the surface, through a permitted well transferred to the Permit Holder, the permitted well shall be plugged by the Permit Holder. Pending plugging of the well, all injection wells within a 1/4 mile radius of the leaking drill hole shall be shut-in until the well is plugged.

l) Leaking Previously Plugged Well

Where any oil and gas reservoir fluids or salt waters are potentially leaking into the USDW or to the surface as determined by geologic and field investigation, through a well plugged under applicable Commission rules, the well shall be replugged by the original Permit Holder responsible for plugging the leaking well. If the original Permit Holder is no longer in existence or cannot be located, the well shall be eligible for plugging through the Arkansas Orphan and Abandoned Well Plugging Fund. Pending plugging of the well all injection wells within a 1/4 mile radius of the leaking well shall be shut-in until the leaking well is plugged.

(Source: 1992 rule book; amended July 13, 2003; amended October, 14, 2007; amended August 17, 2008; amended June 16, 2019; amended December 21, 2020)

RULE B-27: REPEALED

Rule Repealed Effective July 15, 2017

RULE B-28: REPEALED

Rule Repealed Effective November 11, 2007

RULE B-29: REPEALED

Rule Repealed Effective October 15, 2006

RULE B-30: DEVIATION TESTS

The maximum point at which a well penetrates the producing formation shall not unreasonably vary from the vertical drawn from the center of the hole at the surface. Deviations in excess of the following shall be deemed to be unreasonable: More than 3 degrees from the vertical drawn from the center of the hole at the surface.

The Commission shall have the right to make, or to require the operator to make a directional survey of the hole, under the following circumstances: (a) in all cases where the operator has proposed to deliberately drill a directional well from an exceptional surface location and/or to an exceptional bottom hole location; (b) prior to a permit being issued, if an off-set operator requests a directional survey and agrees in writing to pay all costs and expenses of such survey and to assume liability for all risks associated with the survey and further posts a bond in sufficient sum as determined by the Commission as security against all costs and risks associated with the survey or, (c) at any time, by order of the Commission, if the Commission is first presented with substantial evidence that it is likely that the well was drilled other than at the location permitted or that the well has deviated in the direction of a unit boundary to a bottom location which would necessitate an increased penalty upon the well's production allowable. The Commission shall have the continuing jurisdiction to assess the expense and risk of such survey between the operator and any opposing party.

(Source: 1992 rule book; amended July 13, 2003)

RULE B-31: REPEALED

Rule Repealed Effective October 15, 2006

RULE B-32: VACUUM PUMPS PROHIBITED

a) The use of vacuum pumps or other devices for the purpose of putting a vacuum on any gas or oil-bearing stratum is prohibited except in fields using vacuum pumps on January 1, 1939, unless otherwise approved by the Commission or in accordance with subparagraph b) below.

b) Administrative Approval. The Director or his designee is authorized to approve an application for administrative approval of the use of vacuum pumps or other devices for the purpose of putting a vacuum on any gas or oil bearing stratum if the following conditions are met:

1) The application provides proof that the field is practically depleted or the use of vacuum pumps or other devices for the purpose of putting a vacuum on any gas or oil-bearing stratum is otherwise necessary for the prevention of waste.

2) The application includes detailed plat maps indicating current well locations in all included drilling units or leases in uncontrolled pools or fields.

3) Notice has been given to all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9) and no objections were received by the Director in accordance with subparagraph b) 6) below.

4) Each such application is submitted on a form prescribed by the Director, and includes the name and address of each owner, as defined in Ark. Code Ann. (1987) § 15-72-102(9), within each drilling unit in which applicant seeks approval to use the vacuum pump or other devices for the purpose of putting a vacuum on any gas or oil-bearing stratum.

5) Concurrently with the filing of such application, the applicant shall send to each owner specified in subparagraph b) 4) above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), and the date(s) of mailing.

6) Any owner, as defined by Ark. Code Ann. (1987) § 15-72-102(9), noticed in accordance with subparagraph b) 5) above shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director or his designee. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy and such application shall be denied. If the application is denied under this subparagraph, the applicant may file an application for hearing in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

7) An application may be referred to the Commission for determination when the Director or his designee deems it necessary that the Commission make such determination for the purpose of protecting the correlative rights of all parties, in order to prevent waste, or for any other reason. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director or his designee shall give the applicant written notice, citing the reason(s) for referral to the full Commission for determination, and the application shall be denied. If the application is denied under this subparagraph, the applicant may file an application for hearing in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

8) If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subparagraph b) 6), the application shall be approved.

(Source: 1992 rule book; amended July 29, 2011)

RULE B-33: REPEALED

Rule Repealed Effective July 15, 2017

RULE B-34: NOTICE OF FIRE, BREAKS, OR BLOW-OUTS AND REMEDIATION OF ASSOCIATED SPILLS OF CRUDE OIL AND PRODUCED WATER

a) Definitions for purposes of this rule

1) "Permit Holder" shall mean the operator or person, who is duly authorized to develop a lease or unit as owner or through agreement and has the right to drill and produce from any field or reservoir and to appropriate the production for himself or others.

b) Notification

1) Any Permit Holder of an oil, gas and brine production, UIC Class II, and Class V (brine disposal) well or an owner or operator of tanks, storage tanks, or other receiving and storage receptacles into which crude oil is produced, received, or stored, or through which oil is transported in flowlines, shall immediately, but not more than twenty-four (24) hours, notify the Commission Regional Office, where the event has occurred, by telephone or facsimile concerning all fires, blow-outs, spills, leaks or discharges in excess of one (1) barrel of crude oil or five (5) barrels of produced water, which occur at these facilities.

2) All notices of fires, blowouts, spills, leaks, or discharges provided to the Commission Regional Office, shall include the name of the operator responsible and the location of the fire, blow-out, spill leak, or discharge by providing the Section, Township, Range and property, lease, or unit, name. Such report shall also specify what emergency steps have been taken or are in progress to remedy the situation reported.

3) If the reported fire, blow-out, spill, leak, or discharge results in a spill or discharge in excess of one (1) barrel of crude oil and or five (5) barrels of produced water outside the containment, the Permit Holder shall also provide the following in the required written incident report, on a form prescribed by the Director:

A) the amount of crude oil and produced water spilled or discharged,

B) the areal extent of the spill or discharge,

C) the cause of the spill or discharge, and

D) the proposed remediation efforts.

4) Spills or discharges from interstate and intrastate pipeline (downstream from custody transfer), or from refined product pipelines are not covered by this rule and are under the jurisdiction of the Arkansas Department of Environmental Quality (ADEQ).

5) All crude oil and produced water spills or discharges, regardless of amount, which enter Waters of the State as defined in Ark. Code Ann. § 8-4-102 shall be reported immediately to the ADEQ. That portion of the spill which entered Waters of the State shall be under the jurisdiction of the ADEQ for remediation and enforcement purposes.

c) Crude Oil Spill Remediation Requirements

1) All crude oil spills that occur after the effective date of this rule, regardless of amount, from wells, flowlines, tanks, pits or containment dikes are subject to this rule.

2) The Permit Holder is required to initiate the following emergency response procedures for all crude oil spills immediately after a spill has occurred, but not more than 24 hours after the spill:

A) Contain spilled crude oil using earthen dikes, booms and other containment measures to minimize the amount of area affected by the spill.

B) If a spill enters surface waters, the spill shall be contained with booms and/or underflow dams and removed as expeditiously as possible. Further remediation requirements shall be determined by ADEQ in accordance with sub-paragraph (a) (5) above.

C) The cause of spill shall be repaired immediately.

D) Impounded free oil shall be picked up and put in lease storage tanks or removed from the site and recycled.

3) Remaining oil on the land surface shall be removed using absorbent material, which shall be handled as follows:

A) All non-organic/non-biodegradable absorbent materials shall be removed from the site and disposed of at an ADEQ permitted waste treatment or disposal facility or other disposal options as allowed by applicable state law or rule.

B) On-site disposal of organic/biodegradable absorbent materials, such as straw and peat moss, may be disposed through land spreading over the area affected by the initial spill and remediated in accordance with sub-paragraphs (4) (A) thru (D) below.

4) Contaminated soil area affected by a spill may be remediated in place and shall, within 10 days, at a minimum be:

A) fertilized with 13-13-13 fertilizer or an amount of other acceptable fertilizer sufficient to treat the soil with 0.5 lbs per square yard; and

B) limed with sufficient agricultural grade lime over the affected area in order to maintain a pH of between 6-8; if the pH of the soil/oil mixture is less than 6, additional lime shall be incorporated to increase pH above 6; and

C) tilled to a depth of at least 4 inches but no greater than 12 inches to create a soil and crude oil mixture that contains less than 5% total petroleum hydrocarbon (TPH) following the completion of the initial tilling; and

D) watered to maintain soil moisture sufficient to promote plant growth (if extremely dry soil conditions exist); and

E) stabilized to minimize erosion and run-off of stormwater to prevent violation of applicable water quality standards.

F) If the soil in the affected area is frozen or previously saturated due to rain or snow melt, prohibiting compliance with sub-paragraphs (A) thru (E) above, the Permit Holder shall stabilize the area to prevent any surface run-off of crude oil

from leaving the affected area until conditions permit compliance with sub-paragraphs (A) thru (E) above.

G) The soil affected by the spill must contain less than 1% TPH within 12 months after the date of the spill.

H) The Director may require additional remediation action to be taken by the operator, which may include flushing of the area with freshwater (which shall be collected and disposed in a UIC Class II well), the addition of organic material (e.g., peat moss, straw), chemical treatment, additional disking of the soil or soil and absorbent material removal if the soil and/or absorbent material within the spill area cannot meet the TPH standard specified in sub-paragraph (c)(4)(C) above.

I) Contaminated soils removed from the site for off-site disposal shall be disposed of at an Arkansas Department of Environmental Quality permitted landfill permitted to receive such waste other ADEQ permitted surface waste treatment or disposal facility or as required by applicable state law or rule.

5) If a spill enters a public road ditch, visible crude oil-contaminated soil shall be removed from the roadside ditch and:

A) removed from the site in accordance with sub-paragraph (c)(4)(I) above; or

B) incorporated into the non-road ditch area of the spill and remediated in accordance with sub-paragraph (c)(4)(A) thru (E) above.

6) The Permit Holder shall be required to submit on request, or within 15 days after the spill occurred, on a form prescribed by the Director, the following information:

A) a topographic map showing the areal extent of the spill and the proximity of surface waters;

B) the type of soil and current land use;

C) the TPH content in the spill area;

D) explanation of the cause of the spill, and planned efforts to prevent and minimize the effects of future spills at the site.

E) Additional reports are required each 90 days until the spill remediation is completed and approved by the Director.

7) The Commission after notice and hearing shall have the authority to amend the above remediation methodology, or approve alternative remediation methodologies if those methods achieve the same or higher standard of spill remediation.

d) Produced Water Spill Remediation Requirements

1) All spills of produced water, which occur after the effective date of this rule, from wells, flowlines, pits, tanks or containment dikes, shall immediately, but not more than 24 hours be contained using earthen dikes and other containment measures to minimize the amount of area affected by the spill.

2) All impounded produced water shall be picked up and removed from the site for disposal into an approved Class II UIC well, or recycled through the Permit Holder's production process.

3) The affected area shall be limed with at least 50 lbs. of agricultural grade lime per 100 square feet of affected area and tilled to a depth of at least 4 inches.

4) Based on the quantity and areal extent of the produced water spill, the proximity of the spill area to surface water features, the nature of the soil and land use of the area and any impact to public safety, the Director may require additional remediation action to be taken by the Permit Holder. These additional actions may include flushing of the area with freshwater (which shall be collected and disposed in a permitted Class II well), the addition of organic material (e.g., peat moss, hay, straw), additional chemical treatment, additional disking the soil, or soil removal. The operator shall be required to continue these corrective actions until the spill remediation efforts are deemed complete by the Director based on site specific conditions.

(Source: 1992 rule book; amended September 17, 2007)

RULE B-35: DETERMINING AND NAMING COMMON SOURCES OF SUPPLY

Wells shall be classified as to the common sources of supply from which they produce and common sources of supply shall be determined and named by the Commission, provided, that in the event any person is dissatisfied with any such classification or determination, an application may be made to the Commission for such classification or determination, deemed proper and the Commission will hear and determine the same.

In naming the common sources of supply, preference shall be given to common usage and geographical names. Separate common sources of supply within the same area shall preferably be named according to the producing formation.

(Source: 1992 rule book)

RULE B-36: TAKINGS TO BE RATABLE

Every person, now or hereafter engaged in the business of purchasing and selling crude oil or natural gas in this State, shall purchase, without discrimination in favor of one producer against another, or in favor of any one source of supply as against another. For purposes hereof, a distinction shall exist between "crude oil" and "natural gas" purchased from "oil wells" and "gas wells" as those wells are respectively defined within Rule A-4 and takings shall be deemed to be ratable when purchases are made without discrimination between wells within each such separate classification.

(Source: 1992 rule book)

RULE B-37: DUAL COMPLETION OF WELLS

a) A Permit Holder may elect to complete a well in such a manner as to permit the production of oil or gas from one formation through the tubing and oil or gas from a separate formation through the annular space between the tubing and casing, subject to the following conditions:

1) That each well dually completed shall be regarded as a separate and distinct Well; and

2) That the production shall be taken and measured separately; and

3) That all rules and orders governing individual oil or gas wells shall be strictly adhered to.

b) A Permit Holder may file an application with the Director to complete a gas well for production of dry gas from a formation through the annular space between the production casing and the surface casing, provided the following conditions are met:

1) Each application shall be made on a form prescribed by the Director and shall include proof of written notice to all offset operators or owners, as defined in Ark. Code Ann. § 15-72-109, in governmental sections that are contiguous to the lease upon which uncontrolled gas is to be produced; or if controlled, then proof to all offset operators or owners, as defined in Ark. Code Ann. § 15-72-109, having the right to produce from the same shallow formation in the adjacent governmental sections.

2) Surface casing in the subject well has been set and cemented to a depth of as required by General Rule B-15; and

3) The proposed zone to be produced would otherwise not be economic due to limited production potential.

4) Any offset operator or owner noticed in accordance with subparagraph (b)(1) above shall have the right to object to the granting of such application within fifteen (15) days after receipt of the application by the Commission.

5) If an objection is received within fifteen (15) days after receipt of the application by the Commission, or if the Permit Holder does not satisfy all requirements of this paragraph (b), the application shall be denied. If an application is denied the Permit Holder may request to have the matter placed, in accordance with established procedures, on the docket of a regularly scheduled Commission hearing.

6) If no objection is received by the Commission within fifteen (15) days after receipt of the application by the Commission, and the Permit Holder is in compliance with all requirements of this paragraph (b), the application shall be approved.

(Source: 1992 rule book; amended December 16, 2007)

RULE B-38: ESTABLISHMENT OF FIELD RULES

a) An application for the purpose of establishing field rules, and well spacing and drilling units for a new reservoir or pool, except within the covered lands specified in General Rule B-43 or General Rule B-44, shall be submitted, in accordance with General Rules A-2, A-3, and applicable hearing procedures, to the Commission within six months after the initial completion of the discovery well in a pool or reservoir or after the drilling of three wells, whichever occurs first. Prior to receipt of an application, no further permits to drill more than three wells in the same source of supply in the exploratory area as defined by the Director shall be issued.

b) Upon receipt by the Commission of an application for public hearing to establish field rules, well spacing, and drilling units for a reservoir, additional permits beyond the initial three wells may be issued to that reservoir or pool, provided the well permit applications comply with the drilling unit size and well location provision as contained in the application. Permits may continue to be issued until a hearing is held and a decision rendered.

c) The Commission may, after notice and hearing in accordance with General Rule A-2, A-3 and other applicable hearing procedures, grant exceptions to this rule, provided such exceptions will create neither waste nor hazards conducive to waste.

(Source: 1992 rule book; amended September 16, 2006; amended August 17, 2008)

RULE B-39: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE B-40: AUTHORIZATION FOR DIRECTOR OF PRODUCTION AND CONSERVATION TO ADMINISTRATIVELY APPROVE APPLICATIONS FOR EXCEPTIONAL WELL LOCATIONS

a) The Director of Production and Conservation or his designee is authorized to issue a Drilling Permit for a well proposed to be drilled, is being drilled, or has been drilled, but prior to commencement of production, at a location within an established drilling unit, which fails to conform to the drilling unit setback distance requirements as measured from the approximate center of the wellbore to unit boundary lines under applicable field rules or Commission general rules. This rule is only applicable:

(1) To dry gas wells drilled vertically or directionally and does not apply to any type of dry gas well drilled as a wildcat well, as defined in General Rule B-3, or for dry gas wells drilled in Exploratory Units established by Commission order; or

(2) To oil or gas condensate wells drilled in standard drilling units from which the well setbacks are defined by distance from a drilling unit boundary defined by a legal land description and does not apply to drilling units where well setbacks are established by other methods, or for wildcat wells or for wells in Exploratory Units established by the Commission; or

(3) To oil wells located in uncontrolled fields where the standard well setback as specified in General Rule B-3, apply to lease lines rather than drilling unit lines.

b) In each such instance in which a permit is issued, except in uncontrolled fields which are not subject to an allowable, a reduction (penalty) in the allowable to which such well would otherwise be entitled, under the provisions of the applicable field rules or other general well spacing rules, shall be assessed by multiplying a fraction, the numerator of which shall be the distance expressed in feet between the location of such proposed well and the boundary of the drilling unit in which the well is to be drilled and the denominator of which shall be the distance expressed in feet at which wells within such field and/or drilling unit are otherwise required to be located. If the proposed location encroaches upon more than one boundary of said unit, then the penalty to be imposed upon the production allowable shall be cumulative of the penalties from both boundaries as described in sub section 1) below.

1) If the proposed location encroaches upon more than one boundary as specified in section (b) above, the reduction in the allowable shall be calculated as follows:

First boundary encroachment expressed as:

setback footage specified by rule (minus)(-) actual footage of proposed well from unit boundary (divided by)(÷)
setback footage specified by rule, plus (+)

Second boundary encroachment expressed as:

setback footage specified by rule (minus)(–) actual footage of proposed well from unit boundary (divided by)(÷)
setback footage specified by rule = penalty factor

Then:

penalty factor (x) full calculated allowable (MCF or bbl) = amount allowable reduced (MCF or bbl)

Then:

full calculated allowable (MCF or bbl) (minus)(–) amount allowable reduced (MCF or bbl) = production allowable (MCF or bbl)

2) Each such application for an exceptional location shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in A.C.A. § 15-72-102(9), within the drilling unit in which the proposed well is to be drilled and within the drilling units offsetting the boundary line or lines, or in the case of wells in uncontrolled fields within the boundaries of mineral lease lines and the offsetting lease(s), which shall be encroached upon by the proposed exceptional well location.

3) Concurrently with the filing of an application in accordance with this rule, the applicant shall send to each owner specified in sub-section 2) above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners and the date(s) of mailing.

4) Any owner noticed in accordance with sub-section 2) shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy of such objection and the application shall be denied. If the application is denied under this subsection, the applicant may request to have the application placed, in accordance with General Rule A-2, A-3, and other applicable hearing procedures, on the docket of a regularly scheduled Commission hearing for a Commission determination, except that no additional application fee is required.

5) An application may be referred to the Commission for determination when the Director: (1) deems the penalty to be imposed upon the allowable for such well, calculated as herein provided, to be inadequate to offset any advantage which the applicant may have over any other producer, as defined in A.C.A. § 15-72-102(8), by reason of the drilling of the well at such exceptional location, or (2) deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for denial of the application under this rule and the referral to the full Commission for determination.

6) Applications for exceptional locations resulting from directional drilling shall be considered for administrative approval in accordance with this rule, provided, that no allowable shall be authorized until the Commission has been furnished a bottom hole directional survey for each common source of supply for which an allowable is requested. In all such cases where directional surveys are made available, the distance~~,~~ of the mid-point perforations, for each common source of supply in a directional well, from the drilling unit boundary shall be used in calculating the allowable.

7) If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in sub-section 4), the application shall be approved and a Drilling Permit issued.

c) For dry gas wells, as specified in sub-section a) 1) above, an alternative to a reduction in the allowable (penalty) method, as outlines in Section b) above, may be requested if each affected

drilling unit has been previously integrated, by Commission Order or is 100% leased, and is currently held by production, and if all the working interest owners in each affected drilling unit agree, in writing, to share the proceeds from a well which encroaches upon the drilling unit boundary. The below methodology for determining percentages for the sharing of costs, production and royalty among the affected drilling units, may be administratively authorized by the Director or his designee. The method for determining the percentages for sharing the costs of and the proceeds of production from one or more separately metered wells shall be as follows:

1) For vertical or directionally drilled wells, the acreage within an agreed upon area extending out from the perforated internal, as defined in General Rule B-3, shall be calculated for each such separately metered well (the "calculated area"). The calculated area shall be based upon the estimated drainage area of the perforated interval.

2) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

3) Each such application for utilizing the above methodology shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in A.C.A. § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed and which contains a portion of the calculated area as defined in sub-section c) 1) above.

~~4)~~ Concurrently with the filing of an application utilizing the above methodology, the applicant shall send in written authorization from each owner specified in sub-section c) 3) above.

5) An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for denial of the application under this rule and the referral to the full Commission for determination.

6) If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection (c)(5), the application shall be approved and a drilling permit issued.

7) Upon receipt of the drilling permit, the applicant shall give the other working interest parties written notice that the drilling permit has been issued. The working interest parties, who have not previously made an election, shall have fifteen (15) days after receipt of said notice within which to make an election to participate in the well or be deemed as electing non-consent and subject to the non-consent penalty set out in the existing Joint Operating Agreement(s) covering their respective drilling unit.

8) Following completion of the well and prior to the issuance by the Commission of the Certificate of Compliance to commence production, the final location of the perforated interval shall be submitted to the Commission to verify the proposed portion of the calculated area occurring within each drilling unit as specified in sub-section c) 1) above.

(Source: 1992 rule book; amended (Order 1-94(4)) January 25, 1994; amended July 17, 2006; amended December 16, 2007; amended August 17, 2008)

RULE B-41: RULE FOR OPERATION IN HYDROGEN SULFIDE (H_2S) AREAS

Each operator who conducts operations in known areas of Hydrogen Sulfide (H_2S) with minimum concentrations of fifteen (15) ppm under atmospheric conditions or one hundred (100) ppm or more in the gas stream shall provide safeguards to protect the general public from the harmful effects of Hydrogen Sulfide (H_2S). The Director of the Arkansas Oil and Gas Commission shall determine the areas covered by this rule.

Operations shall include drilling, completion, workover, producing, gathering, and storage of hydrocarbon fluids, natural gas and fluids produced in association with Bromine extraction. These operations fall under these guidelines only if they contain gas in the system which has Hydrogen Sulfide (H_2S) as a constituent of the gas.

DEFINITIONS

Radius of Exposure shall mean that radius constructed with the point of escape as its starting point and its length calculated as provided for in General Provisions D.

Area of Exposure shall mean the area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

Public Area shall mean a dwelling, place of business, church, school, hospital, school bus stop, governmental building, a public road, all or any portion of a park, town, city, village, or other similar area that can be populated at any given time.

Public Road shall mean any federal, state, county, or municipal street or road owned or maintained for public access or use.

Contingency Plan shall mean a written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure following the accidental release of a potentially hazardous volume of hydrogen sulfide.

I. GENERAL PROVISIONS

A. Each operator shall determine the Hydrogen Sulfide (H_2S) concentration in the gaseous mixture in an operation or system. Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

B. Each operator shall immediately notify the Arkansas Oil and Gas Commission of any accidental release of Hydrogen Sulfide (H_2S) gas which measures 15 ppm or greater from any point on a radius which exceeds 100 feet from the point of release, or includes any portion of a public area. Such notification shall be followed by a written report which shall be sent to the Commission within ten (10) days of the incident.

C. Each operator shall notify the AOGC before conducting any well servicing activity on any well(s) operated under the provisions of this rule.

D. For all operations subject to a radius of exposure (ROE), that radius shall be determined by the following Pasquill-Gifford Equations

1. ROE = 100 ppm X = $[(1.589)(\text{mole fraction of H2S})(Q)]^{.6258}$

2. ROE = 500 ppm X = $[(0.4546)(\text{mole fraction of H2S})(Q)]^{.6258}$

Where X = radius of exposure in feet
H2S = mole fraction of hydrogen sulfide in the gaseous mixture established by an industry accepted method.
Q =maximum volume of escapable gas in cubic feet per day.

For drilling of a well where insufficient data exist to calculate a ROE, but where Hydrogen Sulfide may be expected, then a radius of exposure shall be three thousand (3000) feet. A lesser - assumed radius may be considered upon written request setting out the justification for same.

E. Wind indicators shall be installed at strategic locations on or near the drilling, workover, or production facility to indicate the wind direction at all times and the safe upwind areas in the event Hydrogen Sulfide becomes present.

II. STORAGE TANK PROVISIONS

Storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a Hydrogen Sulfide (H_2S) concentration in excess of 100 ppm, shall be subject to the following:

A. No determination of a radius of exposure shall be made for storage tanks as herein described.

B. A warning sign shall be posted on or within fifty (50) feet of the facility to alert the general public of the potential danger.

C. All tank hatches shall be kept closed at all times except for when it is necessary to inspect or gauge such tanks. All storage tanks that are not fenced as required in (D.) below are required to be kept secured by lock the hatches on all such tanks when not being inspected or gauged.

D. Entry should be restricted to essential personnel only. As a security measure, fencing is required when storage tanks are inside the limits of a city, townsite or are reasonably exposed to the public. All means of entry shall be locked when the facility is unattended.

E. All H2S fumes and vapors shall be either recovered by a vapor recovery unit, flared through a flare stack with a permanent pilot attached thereon or on a case by case basis vented by permit only. Permits to vent will be reviewed with respect to the distance to the nearest public receptor, the concentration of H2S gas and the volume to be released.

III. WARNING AND MARKER PROVISION

A. A warning sign shall be maintained on all streets or roads which provide access to the facility.

B. Marker signs shall be installed along the pipeline when it is located within a public area and at each public road crossing or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

C. The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words: “Poison Gas” that a potential danger exists.

D. In satisfying the sign requirement, the following will be acceptable:

1. Sign of sufficient size to be readable at a reasonable distance from the facility.

2. Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

IV. CONTROL AND EQUIPMENT SAFETY PROVISION

Operators subject to this provision shall install safety devices and maintain them in an operable condition and shall establish safety procedures designed to prevent the undetected continuing escape of Hydrogen Sulfide (H_2S). Safety devices should be tested annually and a record of each test maintained.

V. DRILLING AND WORKOVER PROVISIONS

A. A certificate of compliance form (HS-1) must be filed with each intent to drill a well in an area and to a depth known to or that may contain Hydrogen Sulfide Gas.

B. Drilling operations are required to be in compliance with the provisions of the rule when the drilled depth is within 1,000 feet of a zone known to or that may contain Hydrogen Sulfide. A variance from the compliance depth may be approved upon written request setting out justification, however the compliance depth will not be less than 500 feet.

C. Protective breathing equipment shall be maintained for all personnel at the site.

D. As a minimum, hydrogen sulfide sensors for drilling or workover rigs shall be located at the rig floor, bell nipple, shale shaker and mud pits unless otherwise approved by the Director.

E. Blowout preventers and well control systems shall be pressure tested initially either to a minimum of 3,000 psig or to 75% of the internal yield (burst) pressure taken from the API casing properties table for the size and grade of casing being used, whichever is less. Thereafter, all well control systems shall be tested prior to reaching compliance depth. The Oil and Gas Commission shall be notified at least four (4) hours prior to the initial "Blowout Preventer and Well Control System Test". The Commission shall have the authority to vary test procedures as is deemed necessary.

F. Secondary remote control of blowout prevention and choke equipment shall be located away from the rig floor at a safe distance from the wellhead.

G. The operator shall install a choke manifold, mud-gas separator and flare line, and provide a suitable method for lighting the flare.

H. Drill Stem Testing:

1. Drill stem testing of Hydrogen Sulfide (H_2S) zones is permitted only in daylight hours.

2. The Oil and Gas Commission shall be notified a minimum of 12 hours in advance of the intention to conduct a drill stem test of a formation containing Hydrogen Sulfide (H_2S). In the event that Hydrogen Sulfide (H_2S) is anticipated during the drill stem test, all testing and safety equipment shall be on location for use as deemed necessary by the Commission.

3. All gas produced from the test shall be flared through a flare system with a pilot and an automatic igniter.

4. Every precaution should be made not to affect the public during the well test. In the event, residents are within the Radius of Exposure or may be affected by a Drill Stem Test, the operator should contact those residents and inform them of the pending action. Special consideration should be given residents with children and/or medical ailments.

I. A supervisory employee or safety company representative that is specifically trained in the operation, maintenance, and testing of all safety equipment and is knowledgeable of the contingency plan and safety procedures must be on site from the compliance depth through the cementing of the long string (production) casing and during the time in which the actual completion work is being performed on the well.

J. API Publication RP-49 and RP-68 is referenced as a suggested guideline for drilling and workover of wells subject to the provision.

VI. CONTINGENCY PLAN PROVISION

A. All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before Hydrogen Sulfide (H_2S) operations are begun.

B. The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public following the accidental release of a potentially hazardous volume of Hydrogen Sulfide (H_2S).

C. The contingency plan shall be activated immediately upon the detection of an accidental release of Hydrogen Sulfide (H_2S) which exceeds fifteen (15) ppm or greater from any point on a radius which exceeds 100 feet from the point of release, or includes any portion of a public area.

D. Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

E. The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

F. The plan shall include a procedure for requesting assistance and for follow-up action to evacuate the public from an area of exposure.

G. The plan shall include a call list which will include the following as they may be applicable:

1. Local supervisory personnel
2. Arkansas Oil and Gas Commission
3. County Sheriff
4. State Police
5. Ambulance Service
6. Hospital
7. Fire Department
8. Contractors for supplemental equipment
9. Office of Emergency Services
10. Other public agencies as needed

H. The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings, residential areas, public facilities such as schools, business locations, public roads or other similar areas where the public might reasonably be expected within the area of exposure. A separate list of all phone numbers should be attached to the plat.

I. A schematic of the facility indicating all equipment on location should be included.

J. The Oil and Gas Commission shall be notified immediately if the contingency plan is activated.

K. The retention of the contingency plan shall be as follows:

1. The plan shall be available for Commission inspection at the well location.

2. The plan shall be retained at the location which lends itself best to activation of the plan.

L. The plan shall be kept updated to insure its current applicability. Each plan must be reviewed and updated annually and a copy of the updated plan submitted to the Commission in January of each calendar year.

VII. TRAINING PROVISION

Each operator and contractor shall provide appropriate Hydrogen Sulfide (H_2S) training for its employees who will be on-site. All personnel must have in their possession, current proof of annual training. This training should include the following:

1. Hazards and characteristics of Hydrogen Sulfide (H_2S).

2. Operations of safety equipment and life support systems.

3. First aid in the event of an employee exposure.

4. Use and operation of Hydrogen Sulfide (H_2S) monitoring equipment.

5. Emergency response procedures to include corrective actions, shutdown procedures, evacuation routes and rescue methods.

(Source: 1992 rule book)

RULE B-42: SEISMIC RULES

(a) Definitions:

1. "Field Seismic Operations" shall mean any geophysical method performed on the surface of the land utilizing certain instruments operating under the laws of physics respecting vibration or sound to determine conditions below the surface of the earth which may contain oil or gas and is inclusive of but not limited to the preliminary line survey, the acquisition of necessary permits, the selection and marking of shot-hole locations, necessary clearing of vegetation, shot-hole drilling, implantation of charge, placement of geophones, detonation and backfill of shot-holes.

2. "Seismic Shoot" shall mean a specific project during which field seismic operations shall be conducted with due diligence, not to exceed or substantially vary from those seismic operations indicated in the original permit application.

(b) Any person desiring to perform field seismic operations within the State of Arkansas shall obtain a permit for each seismic shoot from the Commission prior to commencing field seismic operations. A copy of the approved permit shall be maintained in the central recording unit used for the seismic shoot. Such permit shall be valid for a period of one year from the date of issuance.

(c) The applicant shall make application on a form prescribed by the Director.

(d) Each application as filed shall be accompanied by an application fee of Five Hundred Dollars ($500.00).

(e) Each application for a 2D seismic shoot shall include information and maps, (i) to identify the seismic shoot area, (ii) to indicate the proposed location of all 2D seismic lines, and (iii) to designate an area (each, a "2D Seismic Line Corridor" within which a 2D seismic line may be located or relocated by permitee). No 2D Seismic Line Corridor shall extend farther than one-half (1/2) mile in either direction from the proposed location of the relevant 2D seismic line. Applicants may omit areas within the outer boundaries of any 2D Seismic Line Corridor from the 2D Seismic Line Corridor. Each application for a 3D seismic shoot shall include information and maps to identify the seismic shoot area including the 3D project outline for such seismic shoot. Any relocations of a 2D seismic line or any portion thereof outside the 2D Seismic Line Corridor designated therefore or any increase in a 3D survey outline shall be immediately reported to the Director. The applicant shall also be required to file an amended application showing the revised location of such relocated 2D seismic lines, if applicable. The applicant may also file a request, in writing, that the application with all information and maps, be kept confidential for a period not to exceed twelve (12) months from the date of the filing of the original application. Subject to any applicable exceptions, including without limitation the trade secret exception to the general requirements of Ark. Code Ann. (1987) § 25-19-101 et. seq., said application and any information and maps submitted may be released to the extent required by a court of law or by applicable state law, regardless of the request that such be kept confidential. Said application and any information and maps may also be introduced by the Commission as evidence in any public hearing before the Commission or in any judicial action, regardless of such request; provided, however, that permit holder shall retain the right to object to their admissibility and to seek a closed hearing or a protective order with respect thereto.

(f) The application shall be accompanied with evidence of the appropriate type(s) of financial assurance, as described in General Rule B-2 (d)(1), (2), (3) and (4), and subject to those conditions listed therein.

1. The financial assurance shall be at least fifty thousand dollars ($50,000), but not more than two hundred fifty thousand dollars ($250,000), provided that the aggregate amount of financial assurance required for any applicant for all permits and expired permits issued pursuant to this Rule shall not exceed two hundred fifty thousand dollars ($250,000).

2. The amount of the financial assurance shall be determined by the Director based on, but not limited to, the proximity of the seismic shoot to populated areas, cultural features, sensitive environmental areas, and past Commission enforcement history against the applicant.

3. The financial assurance required to be filed shall remain in effect for one year following the conclusion of all field seismic operations by the permit holder in the State of Arkansas.

(g) Upon review of a completed permit application, the Director shall either issue the permit or deny the permit application. If the permit application is denied, the applicant may file an application for a hearing to appeal the Director's decision in accordance with General Rule A-2, A-3, and other applicable hearing procedures.

(h) No entry shall be made by any person to conduct field seismic operations, upon the lands where such field seismic operations are to be conducted, without the permit holder having first given notice at least ten (10) calendar days prior to commencement of field seismic operations.

1. The notice shall be in writing and given either personally or by certified United States mail to the surface owners reflected in the tax records of the counties where the lands are located, at the mailing addresses identified for such surface owners in such records

2. In instances where it can be reasonably ascertained that there are occupants residing on the lands who are not the surface owners, such notice shall also be given such occupants, unless there is no known mailing address and personal notice cannot reasonably be given. Any such notice to an occupant shall be deemed delivered if delivered personally or deposited in the United States mail postage prepaid to said occupants at the mailing address of the lands.

3. Written notice shall also be given either personally or by certified United States mail to operators, as reflected in the records of the AOGC, of producing wells within the seismic shoot area, at the mailing addresses identified for such operators in said records.

4. The notice shall contain the:

A. Name of the person or entity that is conducting the field seismic operations;

B. Proposed location of the field seismic operations; and

C. Approximate date the person or entity proposes to commence field seismic operations;

(i) The permit holder shall also notify the Commission within five (5) business days of the commencement and completion of each seismic shoot.

(j) All vehicles utilized by the permit holder, or its agents or contractors, shall be clearly identified by signs or markings, utilizing letters and /or numbers a minimum of three (3) inches in height and one-half (1/2) inch wide, indicating the name of such agent.

(k) No shot-hole shall be drilled nor charge detonated within two hundred feet (200') of any residence, water well, oil well, gas well, brine well, injection well or other structure without having first secured the express written authority of the owner(s) thereof and the permit holder shall be responsible for any resulting damages in accordance with this rule. Written authority must also be obtained from the owner(s) if any charge exceeds the maximum allowable charge within the scaled distance below:

DISTANCE TO STRUCTURE (FT)*	MAXIMUM ALLOWABLE CHARGE WEIGHTS (LBS)*
50	0.5
100	2.0
150	4.5
200	8.0
250	12.0
300	18.0
350	25.0

* Based upon a charge weight of seventy (70) FT/LB ½

(l) The maximum allowable charge weight (lbs.) is 25.0, unless the permit holder requests and secures the prior written authorization from the Director.

(m) All holes drilled for field seismic activity shall be properly back filled with soils and/or other suitable material and tamped. A mound may be left over the hole for settling allowance.

(n) All seismic sources placed for detonation for use in field seismic operations shall contain additives to accelerate the biodegradation thereof and shall be handled with due care in accordance with industry standards. The cap leads for any seismic sources that fail to detonate shall be buried at least three (3) feet deep.

(o) All vegetation cleared to the ground for the purposes of field seismic activity shall be cleared in a competent and workmanlike manner in the exercise of due care.

(p) Unless otherwise consented to by the surface owner in writing, permit holder shall not cut down any tree measuring six (6) inches or more in diameter, as measured at a height of three (3) feet from the ground surface unless there are no reasonable alternatives to the removal of such tree(s) available to permit holder. Permit holder shall compensate surface owner the value of all such trees as determined by a forester licensed by the State of Arkansas.

(q) All excessive rutting or soil disturbances resulting from seismic activity shall be repaired or restored to the original condition and contour to the extent reasonable, unless otherwise agreed to by the permit holder and the surface owner in writing.

(r) All fences removed for the purposes of field seismic activity shall be replaced, unless otherwise agreed to by the permit holder and the surface owner in writing.

(s) All debris associated with the seismic activity shall be removed and properly disposed.

(t) Any person who conducts any field seismic operations for a seismic shoot in the state without having obtained a permit therefore shall be subject to a civil penalty of one thousand dollars ($1,000) for each day such field seismic operations continue. Any person who does not fully comply with any other provision of this rule shall be subject to a civil penalty of one thousand dollars ($1,000) for each violation.

(u) Failure to comply with the provisions of this rule or Ark. Code Ann. (1987) § 15-71-114 as amended or any other applicable orders or rules, of the Commission may result in the forfeiture of the financial assurance to remediate damages or recover civil penalties assessed in accordance with subparagraph (t) above.

(v) In addition, any surface owner may seek to recover damages from the financial assurance, as follows:

1. Any surface owner seeking to recover under such financial assurance for damages caused by the performance of such field seismic operations must file written notice of claim, on a form prescribed by the Director, within one (1) year of the date of expiration of the permit; provided however, that such claim shall be subordinate to the rights of the Commission.

2. Any claim received from a surface owner shall be investigated by the Director and a decision shall be rendered by the Director. If the Director's decision is not satisfactory to either the surface owner or the permit holder, either party may file an application for a hearing to appeal the Director's decision in accordance with General Rule A-2, A-3, and other applicable hearing procedures. At a hearing, the surface owner must prove that (a) actual damages occurred, (b) such damages were caused by (i) the negligence of the permit holder, (ii) a violation of this rule by permit holder or (iii) an unreasonable or excessive use of the surface owner's land by the permit holder under the applicable oil and gas lease or other agreement under which the surface owner and/or mineral owner consents to the use of the surface for seismic operations, and (c) the amount of such damages.

3. If the Commission finds that the permit holder is liable to the surface owner for any such damages, the permit holder shall have 30 days from the effective date of the order to pay the surface owner the amount specified by the Commission. If the permit holder fails to pay the amount specified by the Commission to the surface owner, the Director may initiate bond forfeiture proceedings as described in General Rule B-2 (k) to pay damages specified by the Commission, provided however, that such amount shall be subordinate to the rights of the Commission.

4. If the permit holder's financial assurance is forfeited, the permit holder shall cease all field seismic operations until another bond in the same amount of the original bond is filed with the Commission for the same purposes as the original bond.

(Source: 1992 rule book; amended July 3, 2003; amended June 15, 2008)

RULE B-43: ESTABLISHMENT OF DRILLING UNITS FOR GAS PRODUCTION FROM CONVENTIONAL AND UNCONVENTIONAL SOURCES OF SUPPLY OCCURRING IN CERTAIN PROSPECTIVE AREAS NOT COVERED BY FIELD RULES

(a) For purposes of this rule, unconventional sources of supply shall mean those common sources of supply that are identified as the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations, or their stratigraphic shale equivalents, as described in published stratigraphic nomenclature recognized by the Arkansas Geological Survey or the United States Geological Survey.

(b) For purposes of this rule, conventional sources of supply shall mean all common sources of supply that are not defined as unconventional sources of supply in section (a) above.

(c) This rule is applicable to all occurrences of conventional and unconventional sources of supply in Arkansas, Cleburne, Conway, Cross, Faulkner, Independence, Jackson, Lee, Lonoke, Monroe, Phillips, Prairie, St. Francis, Stone, Van Buren, White and Woodruff Counties, Arkansas and shall be called the "section (c) lands". The development of the conventional and unconventional sources of supply within the section (c) lands shall be subject to the provisions of this rule.

(d) This rule is further applicable to all occurrences of unconventional sources of supply in Crawford, Franklin, Johnson, and Pope Counties, Arkansas and shall be called the "section (d) lands". The development of the unconventional sources of supply within the section (d) lands shall be subject to the provisions of this rule. For purposes of this rule, the section (d) lands and the section (c) lands may collectively be referred to as the "covered lands".

(e) All Commission approved Fayetteville Shale and non-Fayetteville Shale fields that are situated within the section (c) lands and that are in existence on the date this rule is adopted (collectively, the "existing fields"), are abolished and the lands heretofore included within the existing fields are included within the section (c) lands governed by this rule. Further, all amendments that added the Fayetteville Shale Formation to previously established fields for conventional sources of supply occurring in the section (d) lands are abolished and continuing development of the Fayetteville Shale and other unconventional sources of supply in these lands shall be governed by the provisions of this rule. All existing individual drilling units however, contained within the abolished fields shall remain intact.

(f) All drilling units established for conventional and unconventional sources of supply within the section (c) lands and all drilling units established for unconventional sources of supply within the section (d) lands shall be comprised of single governmental sections, typically containing an area of approximately 640 acres in size. Each drilling unit shall be characterized as either an "exploratory drilling unit" or an "established drilling unit". An "exploratory drilling unit" shall be defined as any drilling unit that is not an established drilling unit. An "established drilling unit" shall be defined as any drilling unit that contains a well that has been drilled and completed in a conventional or unconventional source of supply (a "subject well"), and for which the operator or other person responsible for the conduct of the drilling operation has filed, with the Commission, all appropriate documents in accordance with General Rule B-5, and been issued a certificate of compliance. Upon the filing of the required well and completion reports for a subject well and the issuance of a certificate of compliance with respect thereto, the exploratory drilling unit upon which the subject well is located and all contiguous governmental sections shall be automatically reclassified as established drilling units.

(g) The filing of an application to integrate separately owned tracts within an exploratory drilling unit, as defined in Section (f) above and as contemplated by A.C.A. § 15-72-302(e), is

permissible, provided that one or more persons who collectively own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such exploratory drilling unit support the filing of the application. In determining who shall be designated as the operator of the exploratory drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) If any non-applicant working interest owner in the drilling unit owns, or has the written support of one or more working interest owners that own, separately or together, at least a fifty percent (50%) working interest in the drilling unit, such non-applicant working interest owner may (i) object to the applicant being named operator (a "section (g) operator challenge") or (ii) file a competing integration application (a "section (g) competing application") that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (g) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (g) competing application shall be postponed until the next month's regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is supported by a majority-in-interest of the total working interest ownership in the drilling unit (the "majority owner"), the majority owner shall be designated unit operator.

4) In the event two parties desiring to be named operator own, or have the written support of one or more working interest owners that own, exactly, an undivided 50% share of the drilling unit and either a section (g) operator challenge is submitted or a section (g) competing application is filed, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

5) If the person designated as operator by the Commission in the adjudication of a section (g) operator challenge or a section (g) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated as operator under the subsequent integration of such drilling unit unless (i) the operator's failure to commence such drilling operations was due to force majeure, or (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding such designated operator) support such operator.

(h) The filing of an application to integrate separately owned tracts within an established drilling unit, as defined in Section (f) above and as contemplated by A.C.A. § 15-72-303 is permissible, without a minimum acreage requirement, provided that one or more persons owning an interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such established drilling unit requests such integration. In determining who shall be designated as the operator of the established drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of

record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) Any non-applicant working interest owner in the drilling unit may object to the applicant being named operator (a "section (h) operator challenge"). In addition, if an objecting party owns, or has the written support of one or more working interest owners that own, separately or together, a larger percentage working interest in the drilling unit than the applicant, such objecting party may file a competing integration application (a "section (h) competing application") that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (h) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (h) competing application shall be postponed until the next month's regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is a majority owner (as defined in subsection (g)(3) above), the majority owner shall be designated unit operator.

4) If a party desiring to be named operator of a drilling unit is not a majority owner, but is supported by the largest percentage interest of the total working interest ownership in the drilling unit (the "plurality owner"), there shall be a rebuttable presumption that the plurality owner shall be designated unit operator. If a section (h) operator challenge to a plurality owner being designated unit operator is submitted by a party that owns, or has the written support of one or more owners that own, separately or together, the next largest percentage share of the working interest ownership in the drilling unit (the "minority owner"), the Commission may designate the minority owner operator if the minority owner is able to show that, based on the factors the Commission deems relevant and the evidence submitted by the parties, the Commission should designate the minority owner as unit operator.

5) If two or more parties that desire to be named operator own, or have the support of one or more working interest owners that own, separately or together, the same working interest ownership in the drilling unit, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

6) If the person designated as operator by the Commission in the adjudication of a section (h) operator challenge or a section (h) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated operator under the subsequent integration of such drilling unit unless (i) the original operator's failure to commence drilling operations on the initial well was due to force majeure, or (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding the original operator) support the original operator.

(i) The well setback from drilling unit boundary lines and spacing between wells, for wells drilled in drilling units for unconventional sources of supply within the covered lands are as follows:

1) Each well location (as defined in Section (a)(2) of General Rule B-3) shall be at least 560 feet from any drilling unit boundary line, unless an exception is granted by the Commission after notice and hearing in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, or in accordance with paragraph (o) below;

2) The perforated interval of the wellbore shall be at least 560 feet in any direction from any other wellbore perforated interval in the same common source of supply that extends across or encroaches upon drilling unit boundaries an exception is granted in accordance with subparagraph (i)5) below);

3) The perforated interval of the wellbore shall be at least 448 feet in any direction, an allowed 20% variance, from all other wellbore perforated intervals in the same common source of supply within an established drilling unit, unless an exception is granted in accordance with subparagraph (i)5) below);

4) No more than 16 wells may be drilled per unit for each separate unconventional source of supply within an established drilling unit unless an exception is granted by the Commission after notice and hearing in accordance with General Rules A-2 and A-3, and other applicable hearing requirements. For purposes of this subsection only, a well is any vertical well, directional well, horizontal well with at a minimum 560 feet of perforated interval in the drilling unit, or if a horizontal does not contain a minimum of 560 feet of perforated lateral in any one drilling unit, then the horizontal well shall be counted in the drilling unit in which the majority of the perforated lateral occurs); and

5) The Director or his designee is authorized to approve an application requesting an exception to subsection (i)2) and/or (i)3) administratively, if the following conditions are met:

A. Each such application shall be submitted on a form prescribed by the Director of Production and Conservation, and include the name and address of each owner, as defined in Ark. Code Ann. (1987) § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed.

B. Concurrently with the filing of the application for an exceptional location in accordance with subsection (i)2) and or (i)3) above, the applicant shall send to all owners, as defined in Ark. Code Ann. (1987) § 15-72-102(9), whose mailing addresses may reasonably be ascertained, in all affected units, a notice of the application's filing and verify such mailing by affidavit, setting out the names and addresses of all owners and the date(s) of mailing. Additionally, if there are any owners, as defined in Ark. Code Ann. (1987) § 15-72-102(9), whose addresses were not reasonably ascertained and notice was not mailed, then the applicant shall also submit proof of publication of such notice in a newspaper of general circulation within the county or counties within which all the units are located that appeared at least one time no earlier than three (3) days prior to filing the application, and no later than five (5) days after filing the application, prior to the Director approving the application administratively.

C. Any owner, as defined in Ark. Code Ann. (1987) § 15-72-102(9), so noticed shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed, then the applicant shall be promptly furnished a copy and such application shall be denied, unless the objection is withdrawn within the original fifteen day time period after receipt of the application. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination in accordance with General Rules A-2 and A-3, and other applicable hearing requirements.

D. If no timely objection is received, or if one is received and withdrawn within the original fifteen day time period after receipt of the application, the Director is authorized to approve the application administratively.

E. An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties, in order to prevent waste, or for any other reason. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for referral to the full Commission for determination. If the application is referred under this section, the applicant shall file a request for a hearing, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

F. If the Applicant has satisfied all applicable provisions, the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection (i)5)C. above, the application shall be approved and a permit issued.

G. Any such application requesting administrative approval may be granted, provided the above criteria is satisfied, prior to the drilling of a well, while a well is being drilled, or after a well has been drilled and completed, but prior to commencement of production.

6) Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other locations in a common source of supply, may be brought before the Commission.

(j) The well spacing for wells drilled in drilling units for conventional sources of supply within the section (c) lands are as follows:

1) Only a single well completion will be permitted to produce from each separate conventional source of supply within each established drilling unit, unless additional completions are approved in accordance with General Rule D-19;

2) Each well location (as defined in Section (a) 2) of General Rule B-3) shall be at least 1120 feet from any drilling unit boundary line;

3) Well completions located closer than 1120 feet from all established drilling unit boundaries, shall be subject to approval in accordance with General Rule B-40; and

4) Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other location in a common source of supply, may be brought before the Commission.

(k) The casing programs for all wells drilled in exploratory and established drilling units established by this rule and occurring in the covered lands specified by this rule shall be in accordance with General Rule B-15.

(l) Wells completed in and producing from only conventional sources of supply, as defined in Section (b), shall be subject to the testing provisions of General Rule D-16 and production

allowable provisions of General Rule D-21. Wells completed in and producing from only unconventional sources of supply, as defined in Section (a), shall not be subject to the testing provisions of General Rule D-16 and allowable provisions of General Rule D-21 There shall be no production allowable established for wells producing from unconventional sources of supply located within the covered lands. Wells completed in and producing from only unconventional sources of supply, within the covered lands, shall report on a form prescribed by the Director, the highest twenty-four (24) hour production rate during the first forty (40) days of production, which form shall be filed within sixty (60) days of the date of first production from the well.

(m) The commingling of completions for unconventional and/or conventional sources of supply within each well situated on an established drilling unit, shall be subject to the provisions and approval process outlined in General Rule D-18. If an unconventional source of supply is approved to be commingled with a conventional source of supply within a well situated on an established drilling unit, the well shall be subject to the production allowable provisions of General Rule D-21.

(n) The reporting requirements of General Rule B-5 shall apply to all wells subject to the provisions of this rule. In addition, the operator of each such well shall be required to file monthly gas production reports in accordance with General Rule D-8.

(o) The Commission specifically retains jurisdiction to consider applications brought before the Commission from a majority in interest of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), in two or more adjoining drilling units seeking the authority to drill, produce and/or share the costs of and the proceeds of production from one or more separately metered wells that extend across or encroach upon drilling unit boundaries and that are drilled and completed in one or more unconventional sources of supply within the covered lands. All such applications shall contain a proposed agreement on the formula for the sharing of costs, production and royalty from the affected drilling units.

1) Encroaching Wells. If a well encroaches upon but does not cross the drilling unit boundary of an adjoining drilling unit (an “encroaching well”), the Commission shall not consider the encroached upon drilling unit to be held by production from the encroaching well.

2) Administrative Approval of Wells that Extend Across or Encroach Upon Drilling Unit Boundaries. If the majority in interest of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), within each drilling unit agree to share a proposed well, a well that is being drilled, or a well which has been drilled, but prior to commencement of production, between two or more adjoining drilling units which are all integrated or are 100% leased utilizing the below methodology for sharing of costs, production and royalty among the affected drilling units, the Director or his designee is authorized to approve the application administratively, if the following conditions are met:

A. The application provides proof that:

i) There is at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-exceptional well location and located entirely within each included drilling unit that is producing or capable of producing gas; or

ii) Within twelve (12) months following the date the well for which administrative approval is granted is spud, there will be at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-

exceptional well location and located entirely within each included drilling unit that is either a well that is producing gas, or a well that is capable of producing gas and awaiting connection to a pipeline; or

iii) There is at least one well or a combination of multiple wells, including cross unit wells and/or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas; or

iv) Within twelve (12) months following the date the well for which administrative approval is granted is spud, there will be at least one well or a combination of multiple wells, including cross unit wells and or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas and awaiting connection to a pipeline; or

v) At least seventy five percent (75%) of the fee mineral ownership within each included drilling unit that does not contain one or more wells satisfying the requirements of subpart 2)A.i) or subpart 2)A. iii) above agree in writing to the well; and

B. Notice has been given to all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9) and no objections were received by the Director in accordance with subsection 2) I) below; and

C. The application includes detailed plat maps indicating current well locations and potential future well development plans in all included drilling units.

D. If administrative approval is granted, based upon either or both of subsection 2)A.ii) or iv) above, and the applicant fails to satisfy one of the conditions specified in subsection 2)A.ii) or iv) above, the drilling permit and all other authorities for the well shall be automatically revoked, and the well shall be shut in, unless the applicant has filed a request in accordance with General Rule A-2, A-3, and other applicable hearing procedures prior to the expiration of the time period specified in such subsections, or the Commission otherwise approves the application.

E. The method for sharing the costs of and the proceeds of production from one or more separately metered wells shall be based on acreage allocation as follows:

i) An area measured 560 feet along and on both sides of the entire length of the horizontal perforated section of the well, and including an area formed by a 560 feet radius from the beginning point of the perforated interval, and a 560 feet radius from the ending point of the perforated interval shall be calculated for each such separately metered well (the “calculated area”).

ii) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

F. Each such application for utilizing the above methodology shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in Ark. Code Ann. (1987) § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed.

G. Concurrently with the filing of an application utilizing the above methodology, the applicant shall send to each owner specified in subsection 2)F. above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), and the date(s) of mailing.

H. Any owner, as defined by Ark. Code Ann. (1987) § 15-72-102(9), noticed in accordance with subsection 2) G) above shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy and such application shall be denied. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

I. An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties, in order to prevent waste, or for any other reason. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for referral to the full Commission for determination. If the application is referred under this section, the applicant shall file a request for a hearing, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

J. If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection 2)I, the application shall be approved and a drilling permit issued.

K. Upon receipt of the drilling permit, the applicant shall give the other owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), written notice that the drilling permit has been issued. The owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), who have not previously made an election, shall have fifteen (15) days after receipt of said notice within which to make an election to participate in the well or be deemed as electing non-consent and subject to the non-consent penalty set out in the existing Joint Operating Agreement(s) covering their respective drilling unit or units.

L. Following completion of the well and prior to the issuance of the Certificate of Compliance to commence production, the final location of the perforated interval shall be submitted to the Director to verify the proposed portion of the calculated area occurring within each drilling unit as specified in subsection 2) E) above.

3) Filing of Affidavit. The Applicant shall also file an affidavit or other document showing the calculated area allocated and assigned to each drilling unit, according to the final calculation of the area, occurring within each drilling unit with the Director and in the real estate property records in all counties where any portion of the drilling units are located.

(p) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in two or more adjoining governmental sections seeking the authority to combine such adjoining governmental sections into one drilling unit for the purpose of developing one or more unconventional sources of supply. In any such multi-section drilling unit, production shall be allocated to each tract therein in the same proportion that each tract bears to the total acreage within such drilling unit.

(q) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in a drilling unit seeking the authority to omit any lands from such drilling unit that are owned by a governmental entity and for which it can be demonstrated that such governmental entity has failed or refused to make such lands available for leasing.

(Source: new rule October 16, 2006; amended December 16, 2007, amended June 15, 2008, amended December 14, 2008; amended March 25, 2010; amended July 05, 2010; amended August 01, 2014; amended October 1, 2015)

RULE B-44: ESTABLISHMENT OF DRILLING UNITS FOR GAS PRODUCTION FROM ALL SOURCES OF SUPPLY OCCURING IN CERTAIN PRODUCING AREAS IN FRANKLIN, LOGAN, SCOTT, SEBASTIAN AND YELL COUNTIES

(a) Definitions:

(1) "Unconventional Sources of Supply" shall mean those common sources of supply that are identified as the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations, or their stratigraphic shale equivalents, as described in published stratigraphic nomenclature recognized by the Arkansas Geological Survey or the United States Geological Survey.

(2) "Conventional Sources of Supply" shall mean all common sources of supply that are not defined as unconventional sources of supply in section (a)(1) above or the Middle Atoka as defined in section (a)(4) below, or a tight gas formation as defined in section (a) (3) below.

(3) "Tight Gas Formation" shall mean tight gas formation as defined in Ark. Code Ann. (1987) § 26-58-101.

(4) "Middle Atoka" shall mean the tight gas formation that is the stratigraphic equivalent, from the top of the Basham Formation to the base of Borum Formation, which includes the Hartford Series, within the covered lands specified in section (b) below.

(b) This rule is applicable to all sources of supply occurring in the "covered lands," except the Hartshorne Coal Formation or any other coal formation. The development of these sources of supply within the covered lands shall be subject to the provisions of this rule. The covered lands are specified as follows:

(1) Sections 19-36, T7N R28W; Sections 1-3 and 11, T6N, R29W all in Franklin County;

(2) Sections 19-36 T7N R27W; Sections 19-36 T7N R26W; Sections 13-36 T7N R25W; Sections 13-36 T7N R24W; Sections 13-36 T7N R23W; all of T6N R28W; all of T6N R27W; all of T6N R26W; all of T5N R29W; all of T5N R28W; all of T5N R27W; all of T5N R26W; Sections 1, 2, 3, 10, 11, 12 T4N R29W; Sections 1-12 T4N R28W; Sections 1-12 T4N R27W; Sections 1-12 T4N R26W all in Logan County and those portions of T6N R25W, T6N R24W and T6N R23W located in Logan County;

(3) That portion of T5N R30W, T4N R29W, T4N R28W, T4N R27W, and T4N R26W located in Scott County; and all of T4N R30W in Scott County;

(4) Sections 31-36 T7N R31W; Sections 31 and 32 T7N R30W; all of T6N R32W; all of T6N R31W; all of T6N R30W; all of T5N R32W; all of T5N R31W; all of T4N R32W and all of T4N R31W in Sebastian County and that portion of T6N R29W and T5N R30W located in Sebastian County;

(5) All of T5N R25W; all of T5N R24W; all of T5N R23W; all of T4N R25W; all of T4N R24W; all of T4N R23W; All of T6N R22W; all of T5N R22W; all of T4N R22W all in Yell County and those portions of T6N R25W, T6N R24W, T6N R23W located in Yell County;

(6) After notice and hearing, the Commission shall retain jurisdiction to expand the covered lands above, to include other lands proven to possess production characteristics similar to the lands initially contained within the covered lands.

(c) The Commission shall retain jurisdiction, after notice and hearing, to determine which other formations, in addition to the Middle Atoka, qualify as tight gas formations within the covered lands.

(d) All Commission approved fields, except those applicable to the Hartshorne Coal Formation or any other coal formation, that are situated within the covered lands and that are in existence on the date this rule is adopted (collectively, the "existing fields"), are abolished and the lands heretofore included within the existing fields are included within the covered lands governed by this rule. However, all existing portions of the abolished fields which are not included in the covered lands, those portions of the fields shall remain intact and operate under the existing field rules for that field or upon order of the Commission may be joined to other existing adjacent fields. All existing individual drilling units however, contained within the abolished fields shall remain intact.

(e) All drilling units established for sources of supply within the covered lands shall be comprised of single governmental sections, typically containing an area of approximately 640 acres in size, unless a different size and/or configuration is approved for any unit or units by Order of the Commission. Each drilling unit shall be characterized as either an "exploratory drilling unit" or an "established drilling unit". An "exploratory drilling unit" shall be defined as any drilling unit that is not an established drilling unit. An "established drilling unit" shall be defined as any drilling unit that contains a well that has been drilled and completed in any source of supply (a "subject well"), and for which the operator or other person responsible for the conduct of the drilling operation has filed, with the Commission, all appropriate documents in accordance with General Rule B-5, and has been issued a certificate of compliance. Upon the filing of the required well and completion reports for a subject well and the issuance of a certificate of compliance with respect there, the exploratory drilling unit upon which the subject well is located and all contiguous governmental sections shall be automatically reclassified as established drilling units. All existing "exploratory drilling units" contiguously located to drilling units with established production at the time this rule is adopted, shall be automatically reclassified as established drilling units.

(f) The filing of an application to integrate separately owned tracts within an exploratory drilling unit, as defined in Section (e) above and as contemplated by A.C.A. § 15-72-302(e), is permissible, provided that one or more persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such exploratory drilling unit agree. In determining who shall be designated as the operator of the exploratory drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) If any non-applicant working interest owner in the drilling unit owns, or has the written support of one or more working interest owners that own, separately or together, at least a fifty percent (50%) working interest in the drilling unit, such non-applicant working interest owner may (i) object to the applicant being named operator (a "section (f) operator challenge") or (ii) file a competing integration application (a "section (f)

competing application") that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (f) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (f) competing application shall be postponed until the next month's regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is supported by a majority-in-interest of the total working interest ownership in the drilling unit (the "majority owner"), the majority owner shall be designated unit operator.

4) In the event two parties desiring to be named operator own, or have the written support of one or more working interest owners that own, exactly, an undivided 50% share of the drilling unit and either a section (f) operator challenge is submitted or a section (f) competing application is filed, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

5) If the person designated as operator by the Commission in the adjudication of a section (f) operator challenge or a section (f) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated as operator under the subsequent integration of such drilling unit unless (i) the operator's failure to commence such drilling operations was due to force majeure, (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding such designated operator) support such operator.

(g) The filing of an application to integrate separately owned tracts within an established drilling unit, as defined in Section (e) above and as contemplated by A.C.A. § 15-72-303 is permissible, without a minimum acreage requirement, provided that one or more persons owning an interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such established drilling unit requests such integration. In determining who shall be designated as the operator of the established drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) Any non-applicant working interest owner in the drilling unit may object to the applicant being named operator (a "section (g) operator challenge"). In addition, if an objecting party owns, or has the written support of one or more working interest owners that own, separately or together, a larger percentage working interest in the drilling unit than the applicant, such objecting party may file a competing integration application (a "section (g) competing application") that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (g) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (g) competing application shall be postponed until the next month's regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is a majority owner (as defined in subsection (f) (3) above), the majority owner shall be designated unit operator.

4) If a party desiring to be named operator of a drilling unit is not a majority owner, but is supported by the largest percentage interest of the total working interest ownership in the drilling unit (the "plurality owner"), there shall be a rebuttable presumption that the plurality owner shall be designated unit operator. If a section (g) operator challenge to a plurality owner being designated unit operator is submitted by a party that owns, or has the written support of one or more owners that own, separately or together, the next largest percentage share of the working interest ownership in the drilling unit (the "minority owner"), the Commission may designate the minority owner operator if the minority owner is able to show that, based on the factors the Commission deems relevant and the evidence submitted by the parties, the Commission should designate the minority owner as unit operator.

5) If two or more parties that desire to be named operator own, or have the support of one or more working interest owners that own, separately or together, the same working interest ownership in the drilling unit, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

6) If the person designated as operator by the Commission in the adjudication of a section (g) operator challenge or a section (g) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated operator under the subsequent integration of such drilling unit unless (i) the original operator's failure to commence drilling operations on the initial well was due to force majeure, (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding the original operator) support the original operator.

(h) The well spacing for wells drilled in exploratory and established drilling units for all unconventional sources of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from other well locations within an established drilling unit, within common sources of supply, unless an exception to this rule is approved by the Commission, following notice and hearing.

(i) The well spacing for wells drilled in exploratory and established drilling units for the Middle Atoka, and any other tight gas formation source of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2) shall be at least 560 feet from other well locations within an established drilling unit, unless the

common sources of supply are stratigraphically different named intervals, approved in accordance with subparagraph (i) (3) below, or an exception to this rule is approved by the Commission, following notice and hearing.

3) Application for approval of well locations less than 560 feet from other well locations within an established unit, for common sources of supply from stratigraphically different named intervals, shall be submitted on a form prescribed by the Director, and contain, at a minimum, the following information:

A) The location of the unit;

B) The location or proposed location of all wells being encroached upon, showing the productive zones in each well;

C) A cross-section, containing the location or proposed location of all wells being encroached upon, demonstrating the productive zone will be from stratigraphically different named intervals;

D) In addition, each application shall provide proof of written notice to all owners, as defined in Ark. Code Ann. § 15-72-102(9), in the subject unit;

E) The notice shall contain at a minimum, the name of the applicant, the name and location of the encroaching wells, and instructions as to the filing with the Director written objections within fifteen (15) days after receipt of the application by the Director.

F) Any owner noticed in accordance with sub-paragraph i) 3) E) above shall have the right to object to the granting of such application within fifteen (15) days after receipt of the application by the Director.

G) If an objection is not received within fifteen (15) days after the receipt of the application, and that the productive zone will be from stratigraphically different named intervals, the Director shall approve the application.

H) If an objection is received, or if the application does not satisfy the requirements of this Rule and is denied by the Director, the Applicant may request to have the matter placed, in accordance with General Rules A-2, A-3 and other established procedures, on the docket of a regularly scheduled Commission hearing.

(j) The well spacing for wells drilled in exploratory and established drilling units for the Upper Atoka and the Freiburg conventional sources of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2) shall be at least 560 feet from other well locations within an established drilling unit, within common

sources of supply, unless an exception to this rule is approved by the Commission, following notice and hearing.

(k) The well spacing for wells drilled in exploratory and established drilling units for all other conventional sources of supply within the covered lands are as follows:

1) Only a single well completion will be permitted to produce from each separate conventional source of supply within each exploratory or established drilling unit, unless additional completions are approved in accordance with General Rule D-19;

2) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 1120 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or General Rule B-40;

(l) The casing programs for all wells drilled in exploratory and established drilling units established by this rule, and occurring in the covered lands specified by this rule, shall be in accordance with General Rule B- 15 or other applicable General Rules.

(m) Wells completed in and producing from all sources of supply, within the covered lands, shall be subject to the testing provisions of General Rule D-16 and allowable provisions of General Rule D-21, except that unconventional sources of supply shall not be subject to an allowable.

(n) The commingling of completions in all sources of supply, within each well, shall be subject to the provisions in General Rule D-18.

(o) The reporting requirements of General Rule B-5 shall apply to all wells subject to the provisions of this rule. In addition, the operator of each such well shall be required to file monthly gas production reports, on a Form approved by the Director, no later than 45 days after the last day of each month.

(p) The Commission specifically retains jurisdiction to consider applications brought before the Commission from a majority in interest of working interest owners in two or more adjoining exploratory or established drilling units seeking the authority to drill, produce and share the costs of and the proceeds of production from a separately metered well that extends across or encroaches upon drilling unit boundaries and that are drilled and completed in one or more sources of supply within the covered lands. All such applications shall contain a proposed agreement on the formula for the sharing of costs, production and royalty from the affected drilling units.

1) However, if the majority in interest of working interest owners agree to share a proposed well between two or more adjoining drilling units, which have been previously integrated, utilizing the below methodology for sharing of costs, production and royalty among the affected drilling units, or if the well encroaches upon the drilling unit boundaries specified by this rule, the Director or his designee is authorized to approve the application administratively utilizing the following methodology:

A) The sharing of well costs and the proceeds of production from one or more separately metered wells, between the affected drilling units, shall be based on an allocation based on an area (acreage) calculation as specified below.

B) For horizontal wells, an area (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) along and on both sides of the entire length of the horizontal perforated section of the well, and including an

area formed by a radius (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) from the beginning point of the perforated interval and from the ending point of the perforated interval. The area formed shall be calculated for each such separately metered well and referred to as the "calculated area".

C) For vertical wells, an area (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) extending around the perforated interval as defined in General Rule B-3, shall be calculated for each such separately metered well and referred to as the "calculated area".

D) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

2) Each such application for utilizing the above methodology shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in A.C.A. § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed.

3) Concurrently with the filing of an application utilizing the above methodology, the applicant shall send to each owner specified in subsection (p)(2) above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners and the date(s) of mailing.

4) Any owner noticed in accordance with subsection (p)(3) above shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy and the application shall be denied. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination, in accordance with applicable state laws and General Rules A-2 and A-3, except that no additional filing fee is required.

5) An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for denial of the application under this rule and the referral to the full Commission for determination, in accordance with applicable state laws and General Rules A-2 and A-3.

6) If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection (p)(4), the application shall be approved and a drilling permit issued.

7) Upon receipt of the drilling permit, the applicant shall give the other working interest parties written notice that the drilling permit has been issued. The working interest parties, who have not previously made an election, shall have 15 days after receipt of said notice within which to make an election to participate in the well or be deemed as

electing non-consent and subject to the non-consent penalty set out in the existing Joint Operating Agreement(s) covering their respective drilling unit or units.

8) Following completion of the well and prior to the issuance by the Commission of the Certificate of Compliance to commence production, the final location of the perforated interval shall be submitted to the Commission to verify the proposed portion of the calculated area occurring within each drilling unit as specified in subsection (p)(1) above.

(q) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in two or more adjoining governmental sections seeking the authority to combine such adjoining governmental sections into one drilling unit for the purpose of developing one or more unconventional sources of supply. In any such multi-section drilling unit, production shall be allocated to each tract therein in the same proportion that each tract bears to the total acreage within such drilling unit.

(r) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in a drilling unit seeking the authority to omit any lands from such drilling unit that are owned by a governmental entity and for which it can be demonstrated that such governmental entity has failed or refused to make such lands available for leasing.

(Source: new rule June 15, 2008; amended January 22, 2009; amended August 01, 2014)

RULE B-45: ESTABLISHMENT OF WELL SET-BACK REQUIREMENTS FOR DRY GAS PRODUCTION WELLS OCCURING IN ESTABLISHED FIELDS IN CRAWFORD, FRANKLIN, JOHNSON, LOGAN, MADISON, POPE, SCOTT, YELL, SEBASTIAN AND WASHINGTON COUNTIES

a) Applicability

1) Except as provided in subparagraph a) 2) below, this rule applies to all controlled sources of supply, as defined in Ark Code Ann. § 15-71-107, occurring within any existing field created by an order of the Commission within Crawford, Franklin, Johnson, Logan, Madison, Pope, Scott, Yell, Sebastian and Washington Counties.

2) This rule does not apply to:

A) The Hartshorne Coal Formation or any other coal formation;

B) Any uncontrolled conventional source of supply occurring within the Commission established fields covered by this rule;

C) Any source of supply governed by General Rule B-43, or

D) Any source of supply governed by General Rule B-44.

3) After notice and hearing, the Commission shall retain jurisdiction to extend the provisions of this rule to any new fields established by the Commission.

4) This rule applies to wells in which controlled and uncontrolled sources of supply are commingled.

b) Definitions

1) "Encroachment Footage" shall mean the actual footage of the New or Existing PRU from the drilling unit boundary, when that footage is less than the Setback Footage specified by rule.

2) "Existing PRU" shall mean a production reporting unit, which is either an individual producing zone or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

3) "FUB" shall mean distance from a drilling unit boundary line.

4) "New PRU" shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

5) "Penalty Allowable" shall mean the PRU Deliverability of the New or Existing PRU, subject to a Penalty Factor, a New or Existing PRU is allowed to produce and sell on a per day basis.

6) "Penalty Factor" shall mean the factor which is multiplied by the New or Existing PRU to impose a penalty (or reduction) upon the PRU Deliverability.

7) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test.

8) “Setback Footage” shall mean the required minimum distance a New or Existing PRU must be from the drilling unit boundary.

c) After the effective date of this rule, the Setback Footage for all drilling units subject to this rule shall be as follows:

1) For all existing drilling units with a Setback Footage that is less than 660 feet, the Setback Footage shall remain unchanged.

2) For all existing drilling units with a Setback Footage that is 660 feet or greater, the revised Setback Footage shall be re-established to 660 feet.

d) After the effective date of this rule, any Existing PRU not subject to a Penalty Allowable may produce at the PRU Deliverability.

e) After the effective date of this rule, any New PRU not subject to a Penalty Allowable may produce at the PRU Deliverability.

f) The Penalty Allowable, for any Existing or New PRU, after the effective date of this rule shall be determined as follows:

1) For any Existing PRU where the Setback Footage is equal to or greater than 660 feet, and where the Setback Footage has been re-established to 660 feet in accordance with subparagraph c) 2) above, the previously imposed penalty on the allowable established prior to the adoption of this rule shall be removed and the Existing PRU allowed to produce at the PRU Deliverability.

2) For any Existing PRU where there is Encroachment Footage, and where the Setback Footage has been re-established to a 660 feet in accordance with subparagraph c) 2) above, the previously imposed penalty on the allowable established prior to the adoption of this rule shall be re-calculated based on the revised Setback Footage of 660 feet in order to calculate the Penalty Allowable, except that any Existing PRU that has a re-calculated Penalty Allowable of less than 75 MCFD shall be assigned a Penalty Allowable of 75 MCFD.

3) For any Existing PRU, where the Setback Footage remains unchanged in accordance with subparagraph c) 1) above, the Penalty Allowable established prior to the adoption of this rule shall remain in effect, except that any Existing PRU that has a re-calculated Penalty Allowable of less than 75 MCFD shall be assigned a Penalty Allowable of 75 MCFD.

4) No New PRU may be located less than 660 feet FUB where the Setback Footage has been re-established to a 660 feet in accordance with subparagraph c) 2) above, or closer than the applicable Setback Footage that remained unchanged in accordance with subparagraph c) 1) above, unless approved in accordance with General Rule B-40, or an alternative is approved by the Commission after notice and hearing.

g) In accordance with subparagraph f) 2) above, the Penalty Allowable shall be calculated as follows:

1) If the Encroachment Footage encroaches upon only one boundary of said drilling unit, the Penalty Allowable shall be the greater of 75 MCFD or calculated as follows:

   Penalty Allowable = PRU Deliverability x Penalty Factor (Encroachment Footage ÷ Setback Footage) x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage

2) If the Encroachment Footage encroaches upon two boundaries of said drilling unit, then the Penalty Allowable shall be the greater of 75 MCFD or the cumulative of the penalties calculated as follows:

   Penalty Allowable = PRU Deliverability x Penalty Factor [(1st Encroachment Footage + 2nd Encroachment Footage) ÷ Setback Footage – 1] x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage

h) Sales in Excess of the Penalty Allowable

1) An Existing or New PRU subject to a Penalty Allowable in accordance with this rule shall have an annual balancing date of July 1, where the preceding 12 month (July 1 – June 30) sales must be reconciled with the preceding 12 month Penalty Allowable to determine if the PRU had excess sales.

2) An Existing or New PRU subject to a Penalty Allowable which has sales in excess of the assigned Penalty Allowable must be shut-in on the annual balancing date of July 1 and remain shut-in until all excess sales is eliminated. The shut-in period shall be determined by dividing the excess sales by the Penalty Allowable.

3) Any Existing or New PRU subject to a Penalty Allowable which has excess sales on the annual balancing date of July 1 and which fails to shut-in within 30 days after the July 1, may be subject to a civil penalty not to exceed two thousand five hundred dollars ($2,500.00) per day for every day the PRU produced beyond the 30 day period, and may be subject to further enforcement actions in accordance with General Rule A-5, and Ark. Code Ann. § 15-72-401 through 15-72-406.

(Source: new rule August 01, 2014)

GENERAL RULE C - OIL

RULE C-1: FIELDS OR POOLS IN WHICH PRODUCTION WILL BE CONTROLLED

All common sources of supply of crude oil discovered after January 1, 1937, if so found necessary by the Commission, will have the production of oil controlled or regulated as provided in Act 105, General Assembly, 1939.

(Source: 1992 rule book)

RULE C-2: REPORTS BY PRODUCERS

A. Each producer of oil in any field, and each producer of hydrocarbons in liquid form at the well head by ordinary production methods from a gas well in any field, shall execute in triplicate and file with the Oil and Gas Commission, El Dorado, Arkansas, a "Producer's Certificate of Compliance and Authorization to Transport Oil or Gas from Lease," for each lease that is capable of producing on or after July 15, 1955.

After the above date, whenever there shall occur a change in operating ownership of any lease in a field within the State of Arkansas, or whenever there shall occur a change of transporter from any lease in a field within the State of Arkansas, a new "Producer's Certificate of Compliance and Authorization to Transport Oil or Gas from Lease," shall be executed and filed in accordance with instructions appearing on such form, except that in the case of temporary change in transporter involving less than the allowable for one month, the producer may, in lieu of filing a new certificate, notify the Oil and Gas Commission at El Dorado, Arkansas, and the transporter then authorized by certificate on file with the Oil and Gas Commission, by letter of the estimated amount of oil to be moved by the temporary transporter and the name of such temporary transporter and a copy of such notice shall also be furnished such temporary transporter. In no instance shall the temporary transporter move any greater quantity of oil than the estimated amount shown in said notice.

The "Producer's Certificate of Compliance and Authorization to Transport Oil or Gas from Lease," when properly executed and approved by the Oil and Gas Commission, shall constitute authorization to the pipeline or other carrier to transport oil from the lease named therein, and shall remain in force and effect until:

(1) The operating ownership of the lease changes, or

(2) The transporter is changed, or

(3) The permit is cancelled by the Oil and Gas Commission.

Where a transporter disconnects from a particular lease or ceases to remove oil therefrom and another transporter connects to such lease or begins to take oil therefrom, during a month, the transporter who ceases to take oil shall furnish to the connecting transporter a certified statement under oath, showing: the legal quantity of oil on hand 7 a.m., the first day of such month; the scheduled allowable to the date disconnected; and the quantity of oil moved from the particular lease during the current month. In such case the producer shall furnish to the connecting transporter a certified statement under oath showing the lease stock on hand 7 a.m., the date of new connection. No connecting transporter shall move oil from any such lease until after it shall have received such statements, except with the written permission of the Oil and Gas Commission or their authorized agent.

Each producer is prohibited from delivering illegal oil to any transporter, and each transporter is prohibited from removing any illegal oil from producer's lease tanks. Each transporter shall maintain necessary records of lease allowables and quantities of oil removed from the leases to which he is connected, whereby he can determine the calculated quantity of legal oil on hand at the close of each calendar month with respect to such leases. The calculated quantity of legal oil on hand with respect to any lease shall be determined for each succeeding month by adding to the quantity of legally produced oil on hand at the first of the month, the scheduled allowable quantity of oil for the respective lease for the current month, as established by the Oil and Gas Commission, less the quantity of oil removed from the respective lease tanks during the current month. If the calculated balance so determined is less than the actual gauged quantity on hand as reported by the

producer on "Producer's Monthly Report," the transporter shall not remove during the following month any part of the oil on hand on the first day of the month in excess of the calculated legal balance so established. If the actual quantity of oil on hand with respect to a particular lease equals or is less than the quantity of legal oil established by the above method, the transporter may remove any part or all of such quantity of oil during the current month. Where actual quantity of oil on hand with respect to a particular lease is less than the calculated quantity of legal oil established by the above method, the transporter, in determining the quantity of legal oil for the next succeeding month, shall substitute the actual quantity on hand for the calculated quantity on hand. Where there is more than one transporter moving oil from the same lease, the producer and transporters are required to furnish to each other information as the quantity of oil on hand, the quantity transported from lease tanks and any additional information necessary to establish to the satisfaction of each person involved the legal status of the oil produced.

B. Each producer of oil in any controlled oil field, and each producer of hydrocarbons in liquid form at the wellhead by ordinary production methods from a gas well in any controlled gas field, shall furnish for each calendar month a "Producer's Monthly Report", setting forth complete information and data indicated by such forms representing oil and/or liquid hydrocarbons produced from each lease operated by said producer in controlled fields in the State of Arkansas. Such report for each month shall be prepared and filed according to the instructions on the form, on or before the 15th of the next succeeding month.

(Source: 1992 rule book)

RULE C-3: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE C-4: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE C-5: OIL ASSESSMENT

Oil conservation assessment, in order to pay the costs in connection with oil and gas conservation administration, not otherwise provided for, shall be made as follows:

A. There shall be assessed a charge not to exceed fifty (50) mills (Acts 2001, No. 1188, General Assembly) on each barrel of crude oil or petroleum marketed or used from a field or pool each month. Said charge and assessment shall only apply to the first purchase or use of oil from the producer and not to subsequent transfers commonly referred to as "tenderships." Effective on and after January 1, 2002, the oil conversation assessment shall be 43 mills.

B. The first purchaser, user or holder for a period of thirty days of the production, who is hereby defined to be the person holding the Division Order and issuing checks to pay for any working interest or royalty interest, shall before issuing checks or otherwise paying for the production, deduct the amount assessed per barrel of oil marketed, used or held for a period or thirty (30) days from the lease each month, and remit the amounts.

C. Said remittance shall be made by the fifteenth of the month following the month in which the oil was purchased in a single check if the purchaser so desires, and the only accounting necessary by the purchaser shall be the show the deductions under this order on the regular payment statements to producers and royalty owners or parties in interest.

D. Any person purchasing oil in this state at the well, under any contract or agreement requiring payment for such production to the respective owners thereof, in respect of which production any sums assessed under this rule as payable to the Commission, is hereby authorized, empowered and required to deduct from any sum so payable to any such person the amount due the Commission by virtue of any such assessment and remit that sum to the Commission in the manner stated. Further, any person taking oil from any well in this state for use or resale, in respect of which production any sums assessed under the provisions of this rule are payable to the Commission, shall remit any sum so due to the Commission in accordance with these rules .

(Source: 1992 rule book; amended Novermber 27, 2001)

RULE C-6: REPEALED

Rule Repealed Effective July 15, 2017

RULE C-7: REPEALED

Rule Repealed Effective July 17, 2009

RULE C-8: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE C-9: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE C-10: ESTABLISHMENT OF WELL SET-BACK REQUIREMENTS FOR OIL PRODUCTION WELLS

a) This rule pertains to oil well setback provisions specified in certain established field rules in Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette, Miller, Nevada, Ouachita, and Union Counties.

b) In all established field rules covered by this general rule, all oil well set back provisions which are measured from a boundary other than the drilling unit boundary, and which are commonly referred to as "bull's-eye" or "race-track" locations for:

1) ten (10) acre drilling units, described as a quarter (¼) quarter (¼) quarter (¼) of a governmental section;

2) twenty (20) acre drilling units, described as the east one-half (E/2), west one-half (W/2), north one-half (N/2) or south one-half (S/2) of a quarter (¼) quarter (¼) of a governmental section;

3) forty (40) acre drilling units, described as a quarter (¼) quarter (¼) of a governmental section; and

4) eighty (80) acre drilling units described as the east one-half (E/2), west one-half (W/2), north one-half (N/2) or south one-half (S/2) of a quarter (¼) of a governmental section;

are set at two hundred and eighty (280) feet from the drilling unit boundary and all existing "bull's-eye" or "race-track" field rule setback requirements for the above drilling units are abolished.

c) Established field rules with well setback requirements less than two hundred and eighty (280) feet from the above drilling unit boundaries, shall remain unchanged.

d) Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other location in a common source of supply, may be approved by the Commission after notice and a hearing in accordance with General Rules A-2, A-3 and other applicable hearing procedures.

(Source: new rule February 19, 2009)

GENERAL RULE D - GAS

RULE D-1: REPEALED

Rule Repealed Effective October 16, 1953.

RULE D-2: REPEALED

Rule Repealed Effective February 19, 2009

RULE D-3: REPEALED

Rule Repealed Effective February 19, 2009

RULE D-4: REPEALED

Rule Repealed Effective February 19, 2009

RULE D-5: REPEALED

Rule Repealed Effective February 19, 2009

RULE D-6: REPEALED

Rule Repealed Effective February 19, 2009

RULE D-7: NATURAL GAS TO BE METRED

a) Wellhead Production Meters:

1) For protection of correlative rights of all parties, the operator of a natural gas well shall meter or caused to be metered all natural gas produced from a well, utilizing a standard industry meter approved by the American Gas Association and capable of recording accurately the volume of natural gas produced at each well, unless another methodology, approved by the Director, is utilized to provide for proper production allocation back to the individual well from a central point production meter or central point sales meter, which ever meter occurs first.

2) All required meters shall be calibrated at least once per calendar year. The records of such calibration shall be maintained or made available by the operator of the well and shall be available for inspection by the Commission. Such records shall be maintained by the operator for a period of at least five (5) years.

3) All required meters shall be accessible and viewable by the Commission for the purpose of monitoring daily, monthly and/or cumulative production volumes from individual wells.

b) Sales Meters:

All meters, measuring the volume of gas sold, shall be calibrated at least once per year. The Director or his designee shall be notified not less than seventy-two (72) hours prior to conducting the meter calibration, so as to allow the Commission to witness such calibration. The records of such calibration shall be maintained by the person responsible for the meter and shall be available for inspection by the commission. Such records shall be maintained by the person responsible for the meter for a period of 5 years.

(Source: 1992 rule book; amended January 22, 2009)

RULE D-8: MONTHLY NATURAL GAS PRODUCTION REPORTS

a) All natural gas produced and sold from oil wells and from gas wells within the State of Arkansas, except natural gas taken into a gasoline, cycling or other extraction plant gathering system, which is required to be reported in accordance with the provisions of Rule F-3, shall be reported by the operator monthly in a form prescribed by the Director. In cases where gas is sold by any person other than the operator, the operator shall remain responsible for reporting all production sold, unless the operator notifies the Director in writing of the name and address of the person other than the operator who has sold gas, the specific month or months for which the person other than the operator who sold gas has failed to report the necessary information to the operator and the approximate well ownership percentage of the person other than the operator who has sold gas. Any person other than the operator who sold gas and failed to report the necessary information to the operator shall then be responsible for reporting the monthly production sold, not otherwise reported by the operator, to the commission.

b) Monthly reports specifying the amount of natural gas produced and sold are required to be filed for each individual producing zone or approved commingled producing zones within a well, regardless of whether or not there was natural gas produced and sold during the month. The reports shall be filed on a form prescribed by the Director and shall be filed with the commission sixty (60) days after the end of each month. Reports for inactive wells shall continue to be submitted until such time as the commission determines monthly reports are no longer required in accordance with applicable commission rules .

c) Where natural gas is delivered to a gasoline extraction plant, cycling plant or any other plant at which butane, propane condensate, kerosene, oil, or other liquid products are extracted from natural gas, such gas shall be reported in accordance with General Rule F-3.

(Source: 1992 rule book; amended November 16, 2008; amended August 21, 2009)

RULE D-9: REPEALED

Rule Repealed Effective July 15, 2017

RULE D-10: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE D-11: REPEALED

Rule Repealed Effective July 15, 2017

RULE D-12: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE D-13: REPEALED

Rule Repealed Effective July 15, 2017

RULE D-14: GAS ASSESSMENT

An assessment to pay the conservation expenses and other costs in connection with administration of gas conservation, not otherwise provided for, may be made as follows:

(A) There shall be assessed against the persons involved, a charge not to exceed ten (10) mills on each one thousand (1,000) cubic feet of gas produced and saved each month from a well. Said assessments shall apply only to the first purchase of gas, or the original taking from the well, and not the subsequent transfers, commonly referred to as "tenderships." Effective on and after January 1, 2002, the gas conservation assessment shall be 9 mills.

(B) The person selling gas at the first point of sale, who is hereby defined to be the party initially responsible for distributing the 1/8 royalty interest shall, before paying for the production, deduct nine (9) mills for every thousand cubic feet of gas produced and removed from the lease each month, and remit the amounts so deducted to the Commission at the same time and periods as said purchasers make their regular gas payments.

(C) Said remittances may be made each month in a single check if the person selling gas at the first point of sale so desires and no accounting by the person selling gas at the first point of sale shall be required except to show all deductions on the regular payment statements to producers and royalty owners or the parities in interest.

(D) The assessment herein provided for shall not apply to gas which is being returned to the ground for repressuring or pressure maintenance purposes within the field, but shall apply only to such gas as is produced and removed from the lease and returned to the ground for storage purposes.

(E) Any person selling gas at the first point of sale in this state at the well, under any contract or agreement requiring payment for such production to the respective owners thereof, in respect of which production any sums assessed under these rules are payable to the Commission, is hereby authorized, empowered and required to deduct from any sum so payable to any such person the amount due the Commission by virtue of any such assessment and remit that sum to the Commission.

Further, any person taking gas from any well in this state for use or resale, in respect of which production any sums assessed under the provisions of this rule are payable to the Commission, shall remit any sum so due to the Commission in accordance with these rules.

(Source: 1992 rule book; amended Novermber 27, 2001; amended October 24, 2009)

RULE D-15: MEASURING GAS AT CUSTODY TRANSFER POINTS

(a) No meter or meter run used for measuring gas at custody transfer points will be equipped with a manifold which will allow gas flow to be diverted or bypassed around the metering element with the following exceptions:

(1) Equipment which permits the changing of the orifice plate without bleeding the pressure off the gas meter run shall not be considered a bypass if flow is bypassed only during normal maintenance or verification operations.

(2) A manifold having block valves on each end of the meter run, and two bypass valves with a bleeder between the bypass valves. During normal operations, the two bypass valves will be closed, with at least one bypass valve sealed, and the bleeder valve will be open and unplugged.

(b) Whenever the manifold described in Section (a)(2) is employed, a notation will be made on the orifice meter chart any time a seal is broken or replaced. This notation will include the seal number broken, the seal number replaced, the reasons for this action, and graphic representation of the estimated gas flow during the time the meter is out of service.

(c) The party choosing to utilize, construct, or operate a bypass of the type described in Section (a)(2) will assume all risks, responsibilities, and liabilities associated with said bypass.

(d) Existing meters used for measuring gas at custody transfer points shall be retrofitted in conformity herewith within twenty-four (24) months from the effective date hereof; provided, however, that meters to be installed at additional transfer points from and after the effective date hereof shall be in conformity herewith.

(Source: 1992 rule book)

RULE D-16: BACK PRESSURE TESTS FOR NATURAL GAS PRODUCTION ALLOWABLE DETERMINATION

a) Applicability

This rule shall only apply to dry natural gas wells for which it is necessary to determine the PRU Deliverability in accordance with General Rules A-7, B-43, B-44, D-19, D-21, or the request of the Director, or his designee, to conduct a back pressure test on a dry natural gas well.

b) Definitions

1) "Existing PRU" shall mean a production reporting unit, which is either an individual sources of supply or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

2) "IOPT" shall mean an Initial One-Point Test performed to determine PRU Deliverability.

3) "New PRU" shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

4) "Permit Holder" shall mean the person to whom the permit is issued and is responsible for all regulatory requirements relative to the production well.

5) "Production Test" shall mean any One-Point Test that is performed to determine PRU Deliverability which occurs after a successful One-Point Test has been performed.

6) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test.

c) An IOPT shall be conducted for any New PRU for the purpose of determining the PRU Deliverability. If a New PRU cannot be tested to determine the PRU Deliverability, a written explanation setting forth in detail the reasons why such IOPT cannot be obtained shall be submitted, along with a request for an alternative methodology to determine the PRU Deliverability.

d) Further Production Testing of an Existing or New PRU following an IOPT is not required except for purposes of retesting at the request of the Permit Holder to establish a penalty allowable in accordance with General Rule D-21, determining marginal well status for severance tax purposes in accordance with General Rule A-7, an additional completion request in accordance with D-19, or if requested by the Director or his designee.

e) IOPT or Production Testing Requirements:

1) Notice – The Permit Holder of the PRU shall provide notice in the manner prescribed by the Director, or his designee, at least seventy-two (72) hour notice in advance of an IOPT or a Production Test.

2) When to Conduct Test – The Permit Holder shall conduct the IOPT within ten (10) calendar days of commencement of production of a New PRU. The Director, or his designee, shall retain the right to require a re-test of an Existing or New PRU at any time.

Additionally, the Permit Holder shall have the right to request a retest of an Existing or New PRU at any time.

3) Filing of Documents – The Permit Holder shall submit the results of the IOPT or Production Test within ten (10) business days of the test date.

4) AOGC Staff Witness – The IOPT is required to be witnessed by a representative of the AOGC unless the Permit Holder is notified by the AOGC that the test shall not be witnessed. Production tests for purposes of establishing marginal well determination, in accordance with General Rule A-7, are required to be witnessed by a representative of the AOGC. AOGC staff witness will be subject to notice by the Permit Holder in accordance with subparagraph (e) (1) above and subject to availability of an AOGC staff witness. All tests shall be conducted during normal working hours of the Commission unless otherwise approved by the Director or his designee.

f) Testing Methodology – An IOPT or Production Test shall be conducted to determine the PRU Deliverability. All tests shall be reported on a form prescribed by the Director, or his designee, and conducted as follows:

1) Before a test is started, the wellbore should be cleared of any accumulated fluids.

2) The Dry Natural Gas from the Existing or New PRU shall be flowed through the production facilities into the pipeline for a minimum of 24 hours. All flow rate measurements shall be obtained by the use of an orifice meter or other authorized metering device in good operating condition previously approved the Director or his designee.

3) Should the flow rate not be obtained to determine PRU Deliverability, the Permit Holder shall provide a written explanation setting forth in detail the reasons why such flow rate could not be obtained in accordance with this procedure. The Director, or his designee, may authorize an alternative method to determine PRU Deliverability.

(Source: 1992 rule book; amended (Order No. 74-94) October 25, 1994; amended October 1, 2000; amended January 14, 2008; amended February 19, 2009; amended August 21, 2009; amended August 01, 2014)

RULE D-17: GENERAL RULE FOR THE REGULATION OF NATURAL GAS PIPELINES

a) Definitions

1) Jurisdictional Pipeline means any onshore natural gas pipeline regulated under Federal Regulation 49 CFR Part 192 as amended, which is within the jurisdiction of the Arkansas Oil and Gas Commission in accordance with Ark. Code Ann. § 15-71-110 as amended.

2) Non-Jurisdictional Pipeline means any onshore natural gas pipeline, including but not limited to flowlines, production lines, or gathering lines, not under jurisdiction of Federal Regulation 49 CFR Part 192 as amended, which is within the jurisdiction of the Arkansas Oil and Gas Commission in accordance with Ark. Code Ann. § 15-71-110 as amended.

3) Perennial Stream means: a stream that has flowing water year-round during a typical year, the water table is located above the stream bed for most of the year, groundwater is the primary source of water for stream flow, and runoff from rainfall is a supplemental source of water for stream flow.

4) Pipeline Operator means any person who owns or operates and is responsible for the construction, operation and maintenance of a natural gas pipeline which transports natural gas from the well within the jurisdiction of the Arkansas Oil and Gas Commission in accordance with Ark Code Ann. § 15-71-110 as amended.

b) Applicability

1) For purposes of this Rule, the jurisdiction of the Arkansas Oil and Gas Commission, as specified in Ark Code Ann. Ann. § 15-71-110 as amended, extends and includes:

A) The production process or production facility as defined in Ark Code Ann. § 15-71-110 as amended; or

B) A natural gas pipeline or associated facility whose owner is not affiliated with an Arkansas natural gas public utility and the majority owner is either a production company or an affiliate of a production company.

2) Every Pipeline Operator transporting natural gas by pipeline from the well is subject to the applicable provisions of this rule. Natural gas pipelines from the well, to a custodial transfer meter located on the well pad, are exempt from the provisions of this rule.

c) General Requirements for all Jurisdictional and Non-Jurisdictional Pipelines:

1) Each Pipeline Operator shall apply, on a form prescribed by the Director, for an initial statewide permit to construct and operate a natural gas pipeline system. The initial permit application shall contain at a minimum the following:

A) Name, address and contact information for the Pipeline Operator;

B) Map, or other media acceptable to the Director, showing the location of all natural gas pipelines from the producing wells through any production or processing equipment or treating facility, and to the termination point of the jurisdiction of the Arkansas Oil and Gas Commission, including all public road, railroads and perennial stream crossings;

C) A determination as to what pipelines are jurisdictional;

D) Submission of the applicable permit fee as follows:

(i) no permit fee is required for 1 mile or less, provided the pipeline does not cross a public road, railroad or perennial stream.

(ii) less than 50 miles of pipeline, including pipelines in (c)(1)(D)(i) above which cross public roads, railroads or perennial streams - $500.00

(iii) 50 miles to less than 100 miles of pipeline - $1,500.00

(iv) 100 miles to less than 250 miles of pipeline -$2,500.00

(v) 250 miles or more of pipelines - $5,000.00

2) Each Pipeline Operator shall be required to submit an annual permit renewal by January 31 of each year.

3) The renewal permit shall include a revised pipeline map showing any new pipeline additions constructed during the previous year, an annual report on a form prescribed by the Director, along with a permit renewal fee in accordance with paragraph (c)(1)(D) above. The renewal permit shall also contain the Pipeline Operator's determination as to which pipelines are jurisdictional.

4) Each Pipeline Operator shall submit a Notice of Construction or Repair, on a form prescribed by the Director, prior to commencing construction or within 48 hours after completing repair, for each segment or project length of pipeline constructed during the year. The Notice shall indicate the location and extent of the natural gas pipelines to be constructed or repaired.

5) Each Pipeline Operator shall notify the Director, or his or her designee, within five (5) calendar days of exceeding any natural gas pipeline's established maximum allowable operating pressure. This shall be submitted on a form prescribed by the Director.

6) Each Pipeline Operator shall submit a Notice of Incident, on a form prescribed by the Director for each incident of release due to natural gas pipeline failure which results in:

A) A death or personal injury requiring in-patient hospitalization; or

B) A total cost of repair, including the value of natural gas lost, of ten thousand dollars ($10,000) or more; or

C) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of subparagraphs (A) or (B) above.

d) Requirements for all Non-Jurisdictional Pipelines

1) All pipelines crossing any stream or stream bed shall comply with applicable state rules and federal regulations. Additionally, any stream crossing of perennial streams, constructed on or after December 16, 2007, shall maintain a minimum of fifty (50) feet of undisturbed stream bank for the protection of the stream. However, the fifty (50) feet of

undisturbed stream bank requirement may be modified by the Director provided that the Pipeline Operator provides proof that the Pipeline Operator has received approval for the crossing from a state or federal agency.

2) Each Pipeline Operator shall place and maintain appropriate signage at all natural gas pipeline crossings of public roads and railroads. The marker should include the words "Warning", "Caution" or "Danger" followed by the words "Gas Pipeline" along with the Pipeline Operator's name and telephone number where the Pipeline Operator can be reached at all times.

3) Each Pipeline Operator which operates natural gas pipelines within the limits of any incorporated or unincorporated city, town or village, shall be a member of a qualified one-call program.

4) All natural gas pipelines, constructed after the effective date of this rule, shall be buried at least twenty-four (24) inches below ground surface, or in accordance with other applicable state or federal laws.

e) Requirements for Jurisdictional Pipelines

1) All Jurisdictional Pipelines shall be in compliance with construction, operation and maintenance requirements contained in Federal Regulations 49 CFR Part 192 Subpart A thru Subpart P as amended, which are herein incorporated by reference.

2) All Jurisdictional Pipelines shall be subject to the applicable enforcement provisions of Federal Regulation 49 CFR Part 190 as amended, which are herein incorporated by reference.

3) All Jurisdictional Pipelines shall be subject to the applicable incident and other reporting requirements contained in Federal Regulation 49 CFR Part 191 as amended, which are herein incorporated by reference, and all such reports shall be submitted to the Arkansas Oil and Gas Commission.

4) All Pipeline Operator of Jurisdictional Pipelines shall be subject to the applicable drug and alcohol testing requirements contained in Federal Regulation 49 CFR Part 199 as amended, which are herein incorporated by reference.

5) All Jurisdictional Pipelines which contain over 100 PPM hydrogen sulfide shall also be subject to the provisions of subparagraph (f) below, unless the provisions of subparagraph (f) are less stringent than any applicable requirement of this subparagraph (e).

f) Additional Requirements for All Pipelines Containing 100 PPM or Greater Hydrogen Sulfide.

1) Construction, Operating and Maintenance Requirements:

A) All pipeline materials must be chemically compatible with any natural gas transported by the natural gas pipeline and such pipeline shall maintain structural integrity under the anticipated temperatures and environmental conditions for which the natural gas pipeline may be exposed, and

B) All piping must be of sufficient thickness or must be installed with adequate protection to withstand anticipated external pressures and loads that will be imposed on the pipe after installation, and

C) No natural gas pipeline may be operated after new construction, repair or relocation until it has been successfully tested for at least one hour with a minimum pressure of 1.25 times the maximum operating pressure to substantiate the maximum operating pressure with all leaks located and eliminated, and

D) All metallic natural gas pipelines must be adequately protected from both external and internal corrosion and the Pipeline Operator is required to submit an annual report, by March 31st of every year for the preceding calendar year, of the effectiveness of the company's corrosion program, with such protection efforts performed by an independent contractor specializing in the control of corrosion.

2) Each Pipeline Operator shall prepare, maintain and follow for each natural gas pipeline, a manual of written procedures for conducting operations, maintenance activities and emergency response. This plan must be reviewed and updated as often as necessary. A review must be conducted annually but not to exceed 15 months between reviews.

3) Each Pipeline Operator shall have a procedure for continuing surveillance of its facilities and take appropriate action regarding, failures, corrosion and operating conditions.

4) Each Pipeline Operator must develop and carry out a damage prevention program to prevent damage to its natural gas pipelines from excavation activities. Each Pipeline Operator shall be a member of the state wide "one-call" system. The plan must have a method of communicating to excavators in the area where the natural gas pipeline is located of the existence of the natural gas pipeline, provide a means of receiving and recording notification of planned excavation activities, provide for temporary marking of the natural gas pipeline and inspection of the natural gas pipeline when the Pipeline Operator has reason to believe it could be damaged by excavation activities.

5) Each Pipeline Operator shall establish written procedures to minimize the hazards resulting from a natural gas pipeline emergency event. Each plan must include at a minimum:

A) Methods of receiving and identifying an event which requires immediate response; and

B) Methods for establishing and maintaining adequate communication with appropriate emergency response and public officials; and

C) Methods for determining safe areas related to evacuation and security during an event; and

D) Methods for training employees of their duties and responsibilities during an event.

6) Each Pipeline Operator shall develop and implement a written continuing public awareness plan which includes provisions for educating the public, appropriate governmental organizations and persons engaged in excavation activities. Use of a one-call notification prior to conducting excavation, possible hazards associated with unintended releases from the natural gas pipeline, physical indications that such a release

may have occurred, steps that should be taken for the safety of the public, procedures for reporting such an event. The program must include activities to advise affected municipalities, schools, businesses and residents along the pipeline right of way. The program and media used must be as comprehensive as necessary to reach all areas in which the Pipeline Operator shall transport gas.

7) Each Pipeline Operator shall establish procedures for analyzing accidents and failures for the purpose of determining the cause of the failure and minimizing the possibility of subsequent reoccurrence.

8) Each Pipeline Operator shall not operate any natural gas pipeline at a pressure that exceeds the documented pressure at which the natural gas pipeline may be safely operated.

9) Each Pipeline Operator shall have a patrol program to observe surface conditions on and adjacent to its pipeline right-of-way for indications of leaks, construction activity, erosion, condition of signage, conditions at public road and railroad crossings and other factors affecting safety and operation of the pipeline. Patrols shall be conducted and documented at least twice each calendar year, not to exceed 7 ½ months between patrols.

10) Each Pipeline Operator shall maintain appropriate pipeline markers at all public road and railroad crossings and along the pipeline at intervals necessary to identify the location of the buried pipeline. The marker should include the words “Warning”, “Caution” or “Danger” followed by the words “Gas Pipeline” along with the Pipeline Operator’s name and telephone number where the Pipeline Operator can be reached at all times.

11) Each pressure relieving device in a compressor station, pressure limiting station or regulator station must be inspected, tested and operated at the pipelines maximum operating pressure, once each calendar year and not to exceed 15 months to determine proper operation.

12) Each remote controlled shutdown device must be inspected and tested once each calendar year and not to exceed 15 months to determine proper operation.

13) Each line valve that serves to block a segment of pipeline and or might be used in an emergency, must be inspected and partially operated once each calendar year and not to exceed 15 months.

14) Each Pipeline Operator shall maintain records associated with operation and maintenance of the pipeline required in this section.

15) Each natural gas pipeline abandoned in place must be disconnected from all sources of gas, purged of gas, filled with freshwater or inert material and sealed at both ends. When a pipeline is being purged all efforts must be taken to (i) prevent the formation of a hazardous mixture of gas and air, (ii) ensure that all safety equipment necessary is present, (iii) remove all non-essential persons from the area and (iv) ensure the public is adequately protected.

(Source: (Order No. 90-97) October 28, 1997; amended December 16, 2007; amended September 14, 2008; amended October 24, 2009; amended January 20, 2014)

RULE D-18: AUTHORITY TO COMMINGLE

a) This rule authorizes the Director of Production and Conservation, or his designee, to approve certain commingle requests as detailed in this rule. This rule is applicable for administrative approval of commingling of multiple common sources of supply on an individual well basis only, and includes previously completed and/or uncompleted sources of supply in a well, with no restriction on rate of production. The rule is not applicable on a field-wide basis.

b) All common sources of supply classified by the Commission as uncontrolled, are exempt from the provisions of this rule and are permitted to be commingled without application, only when commingled with other uncontrolled sources of supply. Upon completion of the commingling activities, reporting in accordance with Rule B-5 is required.

c) All common sources of supply previously approved and commingled in wells before the effective date of this rule are allowed to continue in effect for the life of the well.

d) Commingling is permitted without application for the Middle Atoka, as defined by General Rule B-44 (a) (4). Upon completion of commingling activities, reporting in accordance with Rule B-5 is required.

e) Requests for the commingle of common sources of supply with a well, or at the surface of a well in the following well categories, are not subject to the administrative approval process set forth in this rule, and must be brought before the Commission for approval following proper notice and hearing:

1) A wildcat well; or

2) A well located within an exploratory unit established by Commission Order; or

3) A well in which the commingling of multiple common sources of supply will result in an unapproved additional completion within the drilling unit; or

4) A well in which the primary reservoir drive mechanism for a requested zone to be commingled is a water drive; or

5) A well in which the ownership between the commingled zones is not common, unless all owners, as defined in Ark. Code. Ann. (1987) § 15-72-102(9), in the well agree in writing; or

6) A well in which spacing requirements are different between commingled zones.

f) Application to commingle common sources of supply in accordance with this rule shall be submitted on a form prescribed by the Director of Production and Conservation and shall include, at a minimum:

1) The operator’s contact information;

2) The name and location of the well;

3) The perforated intervals to be commingled;

4) A plat showing well locations in the unit indicating all common sources of supply to be commingled;

5) A statement as to whether the primary reservoir drive mechanism for the requested commingled zone is a water drive;

6) A statement as to whether all zones to be commingled have common spacing requirements;

7) A statement as to whether any of the requested zones to be commingled are subject to a location exception order, the penalty for which will be applied to the commingled production;

8) Proof of notice sent to all offset operators, of the right to drill and produce in all adjacent units, of the intent to commingle.

g) Upon review and approval of the application and if no objections are received by the Director of Production and Conservation within 15 days of the date of the notice sent to each adjacent offset operator or if the application is accompanied by written acceptance by the offset operators of the commingle request, the application for commingling shall be approved. Approved applications are only valid for one year from date of issuance, unless commingling activities have been commenced prior to that time.

h) Following approval of the commingle application, the applicant shall submit to the Director of Production and Conservation, the following:

1. Completed Well Completion and Recompletion Report, and

2. Rates and pressures for each commingled zone, unless a staged frac completion technique has been used in the well.

i) If the Director of Production and Conservation receives an objection to a commingle application during the notice period specified in (f) above, or if the application does not satisfy the requirements of this Rule and is denied by the Director, the applicant may request to have the matter placed, in accordance with General Rules A-2, A-3, and other established procedures, on the docket of a regularly scheduled Commission hearing.

(Source: new rule February 2, 2006; amended January 22, 2009; amended June 5, 2009)

RULE D-19: ADDITIONAL COMPLETIONS WITHIN COMMON SOURCESOF SUPPLY WITHIN A DRILLING UNIT

a) This rule is applicable for administrative approval, by the Director of Production and Conservation, of additional completions, within common sources of supply, within established drilling units located in fields covered by field rules.

b) This rule is not applicable on a field-wide basis, or within Exploratory Units.

c) Application for additional completions shall be submitted to the Director of Production and Conservation on a form prescribed by the Director, and contain the following information:

1) The location of the unit;

2) The location of all well(s) showing the productive zones in each well within the unit for which the additional completions are requested;

3) Initial and current pressure(s) and current rates and, cumulative production for each completion within a common source of supply;

4) A structure and isopach map of the common source of supply;

5) A unit cross-section, including the wells for which the additional completion is requested;

6) A statement as to whether there is common ownership within the wells producing from the common source of supply within the unit; and

7) If applicable, the drainage characteristics for each well within the common source of supply;

d) In addition, each application shall provide proof of written notice to all owners, as defined in Ark. Code Ann. § 15-72-102(9), in the subject unit and all offset operators in all adjacent established units including all owners, as defined by Ark. Code Ann. § 15-72-102(9) in any offset unit where the operator is the same as the applicant.

e) The notice shall contain at a minimum, the name of the applicant, the name and location of the well, the zone subject to the additional completion request, and instructions as to the filing with the Director of Production and Conservation written objections within fifteen (15) days after receipt of the application by the Director of Production and Conservation

f) Any offset operator or owner noticed in accordance with paragraph e) above shall have the right to object to the granting of such application within fifteen (15) days after receipt of the application by the Director of Production and Conservation.

g) Upon review of the application and if the submitted evidence or requested additional evidence indicates that:

1) Stratigraphic or structural separation of the common source of supply can reasonably be demonstrated; or

2) The irregular shape and/or size of the drilling unit relative to the drainage characteristic of the well within the common source of supply necessitate an additional completion; or

3) The drainage characteristics of the well within the common source of supply in a regular shape and size drilling unit demonstrate an additional completion is necessary to effectively drain the unit; or

4) The pressure data from the common source of supply indicates less than a 20% reduction in the original pressure 5 years after the first completion in that same source of supply; or

5) The other unit completion(s) in the common source of supply have each produced less than 75 MCF per day over the twelve month period prior to the additional completion application or a newly drilled well, which is the subject of the additional completion request, and which is only able to produce less than 75 MCF per day absolute open flow; and

6) If ownership within the wells in the common source of supply within the unit is not common, but evidence of agreement between the owners is provided with the additional completion application; and

7) If an objection is not received within 15 days after the receipt of the application, the Director of Production and Conservation shall approve the application.

h) If an objection is received or if the application does not satisfy the requirements of this Rule, the application shall be denied. If an application is denied, or if the reason for an additional completion request is not addressed by this rule, the Applicant may request to have the matter placed, in accordance with established procedures, on the docket of a regularly scheduled Commission hearing.

(Source: new rule February 2, 2006; amended April 13, 2008)

RULE D-20: NOISE LEVEL REQUIREMENTS FOR NON-WELLHEAD COMPRESSOR FACILITIES

a) Applicability:

1) The provisions of this rule apply to all non-wellhead compressor facilities or stations used in the production process, as defined in Ark Code Ann. § 15-71-110 as amended, or whose owner is not affiliated with an Arkansas natural gas public utility and the majority owner is either a production company or an affiliate of a production company.

2) All non-wellhead compressor facilities in operation as of the initial effective date of this rule shall be in compliance with the provisions of this rule by July 1, 2012.

3) All non-wellhead compressor facilities that become operational after the initial effective date of this rule shall be in compliance with the provisions of the rule within one year of commencing compressing operations.

b) Definitions:

1) "ANSI" means the American National Standards Institute, and any reference to an ANSI publication shall refer to the version that was in effect as of January 1, 2011, unless otherwise stated.

2) "Leq" means the Equivalent Continuous Sound Level which is the notional sound pressure level which, if maintained constant over a given time, delivers the same amount of acoustic energy at some point as the time-varying sound pressure level would deliver at the same point and over the same period of time.

3) "Noise sensitive area" means a building with an established mailing address that is being utilized as a private residence, school, hospital, church, nursing home, or other building of a type that is regularly used for overnight accommodation.

4) "Non-well head compressor facility or station" means any compressor facility or station used for the purpose of compressing natural gas for pipeline transportation. This shall not include a compressor facility or station located on a well pad for the purpose of enhancing production of natural gas from the well or wells located on the pad.

5) "Normal full-load operating conditions" means the normal operating condition of the non-wellhead compressor facility or station, excluding accidents, emergency situations, other unforeseen temporary operational deviations, including without limitation the performance of maintenance or construction activities.

c) The noise levels for a non-wellhead compressor facility or station during normal full-load operating conditions shall not exceed 55 dB(A) Leq, as measured from the exterior of the nearest noise sensitive area existing at the time of commencement of initial construction of the non-wellhead compressor facility or station.

d) Noise levels shall be measured as follows:

1) By utilizing a Type 1 sound level meter, as defined in ANSI S1.4, set for A-weighting per ANSI S1.11, and slow meter response.

2) Sound level measurements shall be in substantial compliance with standard environmental acoustical measurement practices as outlined in ANSI S12.9.

3) The Leq contribution due to a non-wellhead compressor facility or station shall be determined using short-term sound level averages taken during periods with minimal audible intrusion from extraneous sources other than the non-wellhead compressor facility or station under test. The following extraneous noise shall be excluded from the measurements to the fullest extent possible:

a) Wind;

b) Vehicular Traffic;

c) Residential heating, ventilating, and air conditioning;

d) Aircraft over-flights;

e) Bird sounds;

f) Insect sounds; and

g) Other noise generating equipment unrelated to the non-wellhead compressor facility or station.

e) Any owner or operator of a non-well head compressor facility or station found to be in violation of the provisions of this rule shall pursue with reasonable diligence a remedy to correct the violation. Any violation shall be considered an "operational" violation in accordance with General Rule A-5.

(Source: new rule November 1, 2011)

RULE D-21: PROCEDURES FOR DETERMINING THE PRODUCTION ALLOWABLE FOR DRY NATURAL GAS PRODUCTION WELLS

a) Applicability

This rule shall only apply to dry natural gas wells for which it is necessary to determine the PRU Deliverability in accordance with General Rules B-43, B-44 and other applicable General Rules, Field Rules or Commission Orders. This rule shall not apply to any PRU subject to provisions of General Rule B-45.

b) Definitions

1) "Allowable" shall mean the PRU Deliverability for a New or Existing PRU is allowed to produce and sell on a per day basis.

2) "Encroachment Footage" shall mean the actual footage of the New or Existing PRU from the drilling unit boundary, when that footage is less than the Setback Footage specified by rule.

3) "Existing PRU" shall mean a production reporting unit, which is either an individual producing zone or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

4) "New PRU" shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

5) "Penalty Allowable" shall mean the PRU Deliverability of the New or Existing PRU, subject to a Penalty Factor, a New or Existing PRU is allowed to produce and sell on a per day basis.

6) "Penalty Factor" shall mean the factor which is multiplied by the New or Existing PRU to impose a penalty (or reduction) upon the PRU Deliverability.

7) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test conducted in accordance with General Rule D-16.

8) "Setback Footage" shall mean the required minimum distance a New or Existing PRU must be from the drilling unit boundary.

9) "FUB" shall mean distance from a drilling unit boundary line.

c) Any New or Existing PRU, not subject to a Penalty Factor in accordance with subparagraph f) below, shall be subject to an allowable as follows:

1) A New or Existing PRU shall have an allowable determined as follows: Allowable = PRU Deliverability x (proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage)

2) A New or Existing PRU with a PRU Deliverability of less than 75 MCFD shall have an

allowable determined as follows: Allowable = 75 MCFD. PRU Deliverability of less than 75 MCFD shall be demonstrated by either:

A) Conducting a test utilizing the methodology specified in General Rule D-16; or

B) Utilizing the most recent six month average daily rate of production for the PRU under actual operating conditions calculated by dividing the total gas reported by the number of days produced during the applicable six month period.

d) Any New or Existing PRU subject to a Penalty Allowable, the Penalty Allowable shall be determined as calculated as follows:

1) If the Encroachment Footage encroaches upon only one boundary of said drilling unit, the Penalty Allowable shall be the greater of 75 MCFD or calculated as follows:

Penalty Allowable = PRU Deliverability x Penalty Factor (Encroachment Footage ÷ Setback Footage) x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage.

2) If the Encroachment Footage encroaches upon two boundaries of said drilling unit, then the Penalty Allowable shall be the greater of 75 MCFD or the cumulative of the penalties calculated as follows:

Penalty Allowable = PRU Deliverability x Penalty Factor [(1st Encroachment Footage + 2nd Encroachment Footage) ÷ Setback Footage -1] x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage

e) Sales in Excess of the Penalty Allowable

1) An Existing or New PRU subject to a Penalty Allowable in accordance with this rule shall have an annual balancing date of July 1, where the preceding 12 month (July 1 – June 30) sales must be reconciled with the preceding 12 month Penalty Allowable to determine if the PRU had excess sales.

2) An Existing or New PRU subject to a Penalty Allowable which has sales in excess of the assigned Penalty Allowable must be shut-in on the annual balancing date of July 1 and remain shut-in until all excess sales is eliminated. The shut-in period shall be determined by dividing the excess sales by the Penalty Allowable.

3) Any Existing or New PRU subject to a Penalty Allowable which has excess sales on the annual balancing date of July 1 and which fails to shut-in within 30 days after the July 1, may be subject to a civil penalty not to exceed two thousand five hundred dollars ($2,500.00) per day for every day the PRU produced beyond the 30 day period, and may be subject to further enforcement actions in accordance with General Rule A-5, and Ark. Code Ann. § 15-72-401 through 15-72-406.

(Source: new rule August 01, 2014)

RULE D-22 – REQUIREMENTS FOR LEASE RIGHTS GAS SUPPLY LINES

a) Definitions

1) "Director" shall mean the Director of the Oil and Gas Commission.

2) "Existing Lease Rights Gas Supply Line" shall mean a pipeline, under jurisdiction of the Arkansas Oil and Gas Commission ("AOGC") as defined in Ark. Code Ann. § 15-71-110, which transports natural gas from a Well Operator Connection, located at a natural gas well, or other natural gas production equipment located upstream of the production meter on the well location, to an end user(s), and was constructed before the initial effective date of this rule (January 15, 2015).

3) "New Lease Rights Gas Supply Line" shall mean a pipeline, under jurisdiction of the Arkansas Oil and Gas Commission ("AOGC") as defined in Ark. Code Ann. § 15-71-110, which transports natural gas from a Well Operator Connection, located at a natural gas well, or other natural gas production equipment located upstream of the production meter on the well location, to an end user(s), and was constructed after the effective date of this rule (January 15, 2015).

4) "Lease Rights Gas Supply Line Operator" shall mean a Lease Rights Gas Supply Line owner who has an agreement authorizing natural gas supply, who accesses directly from the Well Operator Connection, and who owns or operates and is responsible for the construction, operation and maintenance of a Lease Rights Gas Supply Line.

5) "Lease Rights Gas" shall mean the gas owned and controlled by the Lease Rights Gas Supply Line Operator once it passes the Well Operator Connection.

6) "Well Operator Connection" shall mean the point at which the Operator provided access point connects to the Lease Rights Gas Supply Line and at which point the control of the gas by the Well Operator terminates and is assumed by the Lease Rights Gas Supply Line Operator.

b) All Existing and New Lease Rights Gas Supply Lines located downstream of a production meter at the natural gas well or other natural gas production equipment located on the well location, and which is under the jurisdiction of AOGC as defined in Ark. Code Ann. § 15-71-110, are not subject to the provisions of this rule, but shall be subject to all other applicable Federal regulations and State rules governing natural gas pipelines.

c) All New Lease Rights Gas Supply Lines originating at a Well Operator Connection, are subject to the following provisions:

1) Utilizing the services of a plumber licensed by the State of Arkansas, the New Lease Rights Gas Supply Line Operator shall properly install one or more properly-sized regulator(s) on the Lease New Rights Gas Supply Line at the Well Operator Connection point and all necessary piping to accommodate appropriate odorization, gas utilization metering equipment, and a properly-sized regulator at the dwelling or structure where the natural gas is utilized. All materials used shall be designed for natural gas service and provide structural integrity where necessary;

2) Utilizing the services of a plumber licensed by the State of Arkansas, the New Lease Rights Gas Supply Line Operator shall properly install an excess flow valve on the New Lease Rights Gas Supply Line as close to the Well Operator Connection as feasible;

3) Utilizing the services of a plumber licensed by the State of Arkansas, the New Lease Rights Gas Supply Line Operator shall properly install appropriate dehydration facilities on the New Lease Rights Gas Supply Line downstream from the Well Operator Connection, and the Well Operator shall properly install and maintain odorization facilities upstream of the New Lease Rights Gas Supply Line;

4) Utilizing the services of a plumber licensed by the State of Arkansas, New Lease Rights Gas Supply Lines shall be:

A) Constructed of steel or plastic which is designed, manufactured and intended for natural gas service in accordance with industry standards and be tested and free of leaks prior to placing into service. Each test shall be at a pressure of fifty (50) psig for a period of thirty (30) minutes. All piping shall be installed in a manner which will minimize strain or external loading. If plastic pipe is used, it shall be installed so as to minimize tensile stresses and must have a tracer wire or means of locating the pipe while underground. Tracer wire may not be wrapped around the plastic pipe and contact with the pipe should be avoided with at least two (2) inches between the wire and the Lease Rights Gas Supply Line;

B) All New Lease Rights Gas Supply Lines shall be buried and have a minimum of eighteen (18) inches of cover or greater if necessary to not pose a safety hazard to surface activities conducted along the Lease Rights Gas Supply Line right-of-way;

C) All repairs or relocation of a New Lease Rights Gas Supply Line must be performed by a plumber licensed by the State of Arkansas and be in accordance with all applicable above provisions.

5) Install and maintain signage within the line of sight along the New Lease Rights Gas Supply Line, with such signs to include words 1” in height and ¼” in stroke “WARNING – DANGER – NATURAL GAS PIPELINE”, and including the name, address and 24-hour contact information of the New Lease Rights Gas Supply Line Operator; and

6) Provide the Director, or his or her designee, and the Well Operator written notification of the name, address, and telephone number that should be used to notify the New Lease Rights Gas Supply Line Operator of any emergency condition. The New Lease Rights Gas Supply Line Operator shall ensure that this information is kept current with the Director, or his or her designee, and the Operator.

d) For all Existing Lease Rights Gas Supply Lines, the Well Operators providing a Well Operator Connection shall provide the Director with a list of names and addresses of the legally entitled recipients of the Lease Rights Gas, as reflected in the records of the Well Operator. The Director shall send a letter to each Existing Lease Rights Gas Supply Line Operator notifying them of the requirements of this Rule. Within six (6) months from the date the notification letter was sent, all Existing Lease Rights Gas Supply Line Operators shall document compliance with items 1 through 6 below, by the submission of documentation to the Director, or his or her designee. If the Existing Lease Rights Gas Supply Line Operator fails to demonstrate compliance with items 1 through 6 below, or if the Existing Lease Rights Gas Supply Line Operator fails to comply with items 1 through 6 below, the Director or his or her designee may authorize the Operator to disconnect the Lease Rights Gas Supply Line until such time as the Existing Lease Rights Gas Supply Line Operator is in full compliance with the following:

1) The Lease Rights Gas Supply Line Operator shall affirm that the Existing Lease Rights Gas Supply Line is:

   A) Constructed of steel or plastic which is designed, manufactured and intended for natural gas service in accordance with industry standards, that all piping was installed in a manner which will minimize strain or external loading, and is free of leaks; and

   B) Buried and have at least a minimum of eighteen (18) inches of cover or greater if necessary so as not to pose a safety hazard to surface activities conducted along the Lease Rights Gas Supply Line right-of-way; and

2) The Lease Rights Gas Supply Line Operator shall also affirm that all plastic pipping has a tracer wire installed with the piping, or other means of locating the pipe underground. Tracer wire may not be wrapped around the plastic pipe and contact with the pipe should be avoided with at least two (2) inches between the wire and the Lease Rights Gas Supply Line. Trace wire or other means of locating the pipe underground, is required when the Existing Lease Rights Gas Supply Line:

   A) Crosses public or private roads, or creeks; or

   B) Crosses any property not owned by the Lease Rights Gas Supply Line Operator; or

   C) Is within twenty-five (25) feet of the Lease Rights Gas Supply Line Operator's property line(s).

3) Existing Lease Rights Gas Supply Line Operators shall properly install, or maintain, one or more properly sized regulators on the Lease Rights Gas Supply Line at the Well Operator Connection, and properly install, or maintain, an excess flow valve as close to the Well Operator Connection as reasonably possible.

4) All repairs or relocation of an Existing Lease Rights Gas Supply Lines must be performed by a plumber licensed by the State of Arkansas and be in accordance with all applicable above provisions.

5) Existing Lease Rights Gas Supply Line Operators shall install and maintain signage within the line of sight along the Existing Lease Rights Gas Supply Line, with such signs to include words 1" in height and ¼" in stroke "WARNING – DANGER – NATURAL GAS PIPELINE", and including the name, address and 24-hour contact information of the Lease Rights Gas Supply Line Operator; and

6) Existing Lease Rights Gas Supply Line Operator shall provide the Director, or his or her designee, and the Operator written notification of the name, address, and telephone number that should be used to notify the Lease Rights Gas Supply Line Operator of any emergency condition. The Lease Rights Gas Supply Line Operator shall ensure that this information is kept current with the Director, or his or her designee, and the Operator.

7) The Well Operator shall properly install and maintain odorization facilities upstream of the Lease Rights Gas Supply Line.

e) Produced fluids collected by the New or Existing Lease Rights Gas Supply Line Operator shall be removed from the site and disposed in accordance with applicable Arkansas Oil and Gas

Commission and Arkansas Department of Environmental Quality rules . Produced fluids shall not be discharged onto the ground surface or into waters of the state. Any spill of produced fluids shall be remediated in accordance with applicable Arkansas Oil and Gas Commission and Arkansas Department of Environmental Quality rules .

f) Unless otherwise authorized in the agreement authorizing the natural gas supply, all Existing Lease Rights Gas Supply Lines servicing multiple domestic or end users are prohibited, and within six (6) months from the date the notification letter sent in accordance with subparagraph (d) above, the Lease Rights Gas Supply Line Operator shall reconfigure the Lease Rights Gas Supply Line to only allow for a single domestic or end user per Lease Rights Gas Supply Line. Unless otherwise authorized in the agreement authorizing the natural gas supply, New Lease Rights Gas Supply lines shall only allow for a single domestic or end user per Lease Rights Gas Supply Lines.

g) All Lease Rights Gas Supply Lines Operators shall maintain compliance with the provisions of this Rule. If a Lease Rights Gas Supply Line Operator fails to comply with the provisions of this Rule, the Director or his or her designee shall give Notice of the Violation, in accordance with General Rule A-5, to the Lease Rights Gas Supply Line Operator. The Lease Rights Gas Supply Line Operator shall have thirty (30) days to comply with the Notice of Violation. If the Lease Rights Gas Supply Line Operator fails to comply or properly request a review or appeal in accordance with General Rule A-5, then the Director or his or her designee may authorize the Operator to disconnect the Lease Rights Gas Supply Line until such time as the Lease Rights Gas Supply Line Operator is in full compliance with the provisions of this Rule. Any appeal of a Director's Decision for a Notice of Violation issued in accordance with this subparagraph shall not be subject to the filing fee required in accordance with General Rule A-2 or A-3.

h) Lease Rights Gas Supply Line Operators are no longer subject to the provisions of this rule if the well, where the Well Operator Connection is located, is transferred to the Lease Rights Gas Supply Line Operator in accordance with General Rule B-11.

(Source: new rule January 15, 2015; amended March 1, 2016)

RULE D-23: GENERAL RULE FOR THE REGULATION OF UNDERGROUND NATURAL GAS STORAGE PROJECTS

a) Authority and Applicability

1) The underground storage of Natural Gas promotes conservation, permits the building of reserves for orderly withdrawal in periods of peak demand, makes more readily available and economical natural gas resources to the domestic, commercial, and industrial consumers, and promotes the public interest and welfare of the State of Arkansas. Therefore, the Arkansas Oil and Gas Commission may find and determine, in accordance with Ark. Code Ann. § 15-72-603, that the underground storage of natural gas is in the public interest.

2) All Natural Gas Public Utilities engaged in the process of the storage of natural gas in underground reservoirs within the State of Arkansas, as specified in Ark Code Ann. § 15-72-601, et seq., are subject to the provisions of this rule. This rule does not apply to gas injection or withdrawal operations conducted as a part of, or in conjunction with, any secondary or tertiary recovery methods utilized in a unitized pool or unit area established by the Commission.

3) Underground Storage Facilities established by the Commission, which are in existence at the time of the adoption of this rule, are not subject to the provisions contained herein with the exception of subparagraph (n) below.

4) All Underground Natural Gas Storage Facilities are subject to the provisions of this rule unless any provisions contained herein are less stringent than any applicable federal requirement enumerated in subparagraph (n).

b) Definitions

1) "Certificate of Storage" shall mean an order issued by the Commission that:

A) Identifies an underground stratum or formation that is suitable for the underground storage of natural gas and that its use for such purposes is in the public interest;

B) Designates the horizontal and vertical boundaries of the storage facility, such boundaries to include any necessary or reasonable buffer zone for the purpose of ensuring the safe operation of the storage facility and to protect the storage facility from pollution or invasion, or escape or migration of gas therefrom;

C) Designates the minimum and maximum operating pressures of the storage facility;

D) Designates the storage operator for said facility; and

E) Adopts special rules for the operation of the facility.

2) "Commission" shall mean the Oil and Gas Commission.

3) "Cushion Gas" shall mean the volume of gas required as permanent storage inventory to maintain adequate reservoir pressure to meet minimum gas deliverability demand (also called "base gas").

4) "Gathering Line" shall mean a pipeline that transports gas from a current production facility to a transmission line or main.

5) "Native Gas" shall mean gas which has not been previously withdrawn from the earth;

6) "Natural Gas" shall mean all natural gas, casinghead gas, and occluded natural gas found in coalbeds, and all other hydrocarbons not defined as oil in General Rule A-4, but not including liquid petroleum gas.

7) "Natural Gas Public Utility" shall mean any person, firm, corporation or entity engaged in the business of producing, transporting, or distributing Natural Gas by means of pipelines into, within, or through this State for ultimate public consumption.

8) "Observation Well" shall mean any well drilled or converted for the purpose of monitoring reservoir pressures, temperatures, or integrity of a USR.

9) "Storage Operations" shall mean the process of injecting Natural Gas into a USR.

10) "Storage Operator" shall mean any company, person, corporation, partnership, limited partnership, association of persons, municipality, association of municipalities, public utility, gas district, or any other entity, authorized by the Commission to operate any USF.

11) "Storage Well" shall mean any well drilled or converted, within a USF, for the purpose of Natural Gas injection and Natural Gas withdrawal.

12) "Underground Storage" shall mean the storage of Natural Gas in an USR.

13) "Underground Storage Facility" (USF) shall mean a USR, the injection and withdrawal wells and well tubular goods, the wellhead, and related equipment to the last positive shut-off valve before the gathering line that is used or to be used for the underground storage of Natural Gas, and all surface and subsurface rights and appurtenances necessary or useful in the operation of the facility for the underground storage of Natural Gas, including any necessary or reasonable buffer zone as identified and recommended by the Storage Operator and approved by the Commission for the purpose of ensuring the safe operation of the storage of Natural Gas, and to protect the storage facility against pollution or invasion, or escape or migration of Natural Gas therefrom.

14) "Underground Storage Reservoir" (USR) shall mean any porous subsurface sand, stratum, or formation which is completely separated from any other porous zone and is suitable for, or capable of, being made suitable for the injection and storage and withdrawal of Natural Gas.

15) "Working Gas" shall mean the portion of the storage volume that can be removed from a USR for deliveries, and still maintain pressure sufficient to meet design deliverability.

c) Eminent Domain

1) Any Natural Gas Public Utility desiring to exercise the right of eminent domain in accordance with Ark. Code Ann. § 15-72-606, to acquire or take any property for the

Underground Storage of Natural Gas, shall first obtain from the Commission a Certificate of Storage setting forth the following:

A) The amount of recoverable oil and Native Gas, if any, remaining in the USR and a determination as to proper allocation of that amount;

B) That the property to be taken or acquired is suitable for the Underground Storage of Natural Gas; and

C) That the use of the USR for storage of Natural Gas is in the public interest.

2) The Natural Gas Public Utility shall present to the circuit court of the county wherein the land is situated, or to the judge thereof, a petition setting forth the purpose for taking the property, a legal description of the property to be taken, and the names of the title owners thereof as shown in the public record of the county.

3) The petitioner shall file the Certificate of Storage issued by the Commission as a part of its petition, and no order by the court granting the petition shall be entered without the Certificate of Storage being filed therewith.

d) Issuance Certificate of Storage

1) Any Natural Gas Public Utility may file an application to have the Commission issue a Certificate of Storage for the Underground Storage of Natural Gas in a USR.

2) The Commission shall publish notice at least once each week for two (2) successive weeks in a newspaper of general circulation in the county or counties where the proposed USR is to be located. The first publication of the notice must be at least ten (10) days prior to the date of the hearing.

3) Only the area of the USR that may reasonably be expected to be penetrated by Natural Gas displaced or injected into the USR, as determined by the Commission, may be covered by the Certificate of Storage.

4) The Certificate of Storage granted in this section shall not prejudice the rights of the owner or owners of the lands (or of other rights or interests therein), to drill or bore through the USR as established by rules of the Commission, and shall not prejudice to the rights of the owner or owners of the lands (or other rights or interests therein) as to all other uses of the lands not inconsistent with the operation of the USF.

5) All Natural Gas which has been reduced to possession and which is subsequently injected into a USR shall at all times be deemed the property of the Storage Operator, or his or her heirs, successors, or assigns. This Natural Gas shall not be in any manner subject to the right of the surface owner of the lands or the owner of any mineral interest under or above the USF, or subject to the right of any other person or entity. The Storage Operator, or his or her heirs, successors, and assigns, has the sole and only right to produce, take, or reduce to possession this Natural Gas in the USR, and no other person may waste, or otherwise interfere with or exercise any control over the USR or any Natural Gas therein. The Storage Operator, or his or her heirs, successors, and assigns, shall have no right to Natural Gas in any other underground reservoir that is not subject to the Certificate of Storage.

6) After notice and hearing, the Commission may issue a Certificate of Storage if it affirmatively finds, based upon substantial evidence, that the proposed USR is geologically suitable and has a greater value or utility as a USR for the purpose of ensuring an adequate supply of Natural Gas for any particular class or group of consumers of Natural Gas, or for the conservation of Natural Gas, than for the production of relatively small volumes of Native Gas which may remain therein. The Commission shall not issue a Certificate of Storage if the proposed USR is capable of producing oil, in paying quantities, through any known recovery method, or is a USDW as defined in General Rule H-1.

e) Contents of Application for Certificate of Storage

1) No USF shall be constructed or operated without the Storage Operator obtaining or holding the necessary and sufficient property rights for construction and operation of the USF. The Storage Operator shall provide evidence of holding such rights for any real or personal property, or evidence the Storage Operator can obtain such property through eminent domain proceedings related to that property. A Certificate of Storage shall expire twelve (12) months from the date of issuance if the Storage Wells have not been drilled and completed, or within twenty-four (24) months if the Storage Wells have been drilled and completed and if Storage Operations have not commenced.

2) Application for a Certificate of Storage shall include the following:

A) A plan view map showing:

i) The surface and extent of the USF, indicating the proposed location of Storage Wells, Observation Wells, and the location of all proposed pipelines and other surface facilities within the boundary of the USF;

ii) Locations of all other wells or boreholes, including but not limited to, water wells, oil and natural gas exploration and development wells within the boundary of the USF and extending ¼ mile outside the boundary of the USF;

iii) The subsurface extent of the USR and any buffer zone.

B) Applicant shall submit evidence and/or information showing that the proposed USR is not a USDW, and identify any freshwater bearing horizons known to be developed in the immediate vicinity of the USR.

C) Applicant shall conduct an evaluation to identify any productive oil and natural gas zones occurring stratigraphically above, below, or within the USR, and if productive natural gas zones are present within the USR, the applicant shall identify and determine the remaining reserves of Native Gas within the USR.

D) A geologic evaluation of the USR, including an isopach map of the USR, a structure map of the top and base of the USR, identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored Natural Gas, and a structural and stratigraphic cross-section that describes the geologic conditions of the USR.

E) A geologic evaluation of all existing information on all geologic strata overlying the USR, including the immediate containment formation (caprock)

characteristics and all designated subsurface monitoring zones. The evaluation shall focus on the proposed USR and provide a description of mechanisms of geologic confinement with regard to the ability of that confinement to prevent migration of Natural Gas beyond the proposed USR. The evaluation shall include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features which may impact confinement.

F) A review of all wells within the proposed USR, which penetrate the USR or primary and/or secondary confining layers overlying the USR, and all the wells, within one mile of the USR, which penetrate the geologic formation to be used for storage. This review shall determine if all abandoned wells have been plugged, and whether all unplugged wells are constructed in a manner that prevents the movement of Natural Gas from the USR.

G) The proposed calculated maximum volume of the USR to be used for storage, shall include Working Gas, Native Gas, and Cushion Gas volumes. In the event the Storage Operator of a USF recalculates the actual reservoir volume determined and identified to the Commission after continued operation of the Storage Facility, then the Storage Operator shall file an application for a redetermination of the allowed volume.

H) The proposed maximum bottom-hole injection pressure to be utilized for the USR shall be measured in psig, shall be no greater than ninety percent (90%) of the formation fracture pressure as determined by a step-rate test (or other approved method), unless a higher percentage is approved by the Commission. The USR shall not be subjected to injection pressures in excess of the calculated fracture pressure. The maximum allowable stabilized reservoir pressure (gauge) shall be no greater than seventy-five percent (75%) of the fracture pressure of the USR, as determined by a step rate test or as calculated by a method acceptable to the Commission. The average USR pressure shall be no greater than ninety percent (90%) of the fracture pressure.

I) A corrosion monitoring and prevention plan for all wells and surface facilities, and a leak detection and monitoring plan for surface facilities and wells, which shall include subsurface observation wells to monitor any movement of Natural Gas from the USR.

J) A detailed description of the proposed public safety and emergency response plan. The response plan shall detail the safety procedures concerning the USF and any residential, commercial, and public land use within one (1) mile, or any other distance as deemed necessary by Commission beyond the outside boundary of the USF. The plan shall include contingency plans should Natural Gas leak from any well, flow line, or any other USF. These emergency response procedures should be updated as necessary throughout the operational life of the USF.

K) Authority to conduct an injectivity test, step rate test, or other injection test to determine the suitability of the USR, prior to the issuance of the Certificate of Storage. This authority may be approved by the Director upon issuance of the test well permit in accordance with subsection (f) below. The Director shall establish the parameters of the test for the protection of public safety, the USDW, and any

oil and gas resources potentially impacted by the test, and may require the submission of any information or test data deemed necessary.

f) Permitting Storage Wells

1) No person shall drill, deepen, re-enter, recomplete or operate any Storage or Observation Well until a Certificate of Storage and applicable well permits have been issued by the Commission, application for which shall be made on forms prescribed by the Director. Permits are valid only for the permit holder stated on the permit, and shall remain valid only if the permit holder is in compliance with established operating requirements specified in this rule. Permits to drill, deepen, or re-enter shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit has occurred and are continued with due diligence, but not to exceed one (1) year from the date of commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit. If the activity authorized in the permit is not completed within one (1) year, the well shall be plugged, casing set, or a new permit application, along with a new permit fee and plat, must be filed. Failure to comply with the operating requirements in this rule may result in revocation of the Storage or Observation Well permit in accordance with General Rule B-1 (c).

2) No Storage Well or Observation Well may be drilled at a surface location other than that specified on the permit. However, if a permit holder has commenced drilling operations and the Storage or Observation well is lost due to adverse drilling conditions prior to surface casing being set, the permit holder may request an amendment of the permit without a fee for the new location, provided the Storage or Observation Well remains on the same property where the Storage or Observation Well was originally permitted, and all other aspects of the permit request remain the same. Movement of the Storage or Observation Well location off the original surface owners' property, or after surface casing has been set, will require the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

3) Upon issuance of a permit, a copy of the permit shall be displayed at the site where the Storage Well or Observation Well is being drilled for review by Commission staff.

4) The application to drill, deepen, re-enter or recomplete a Storage Well or Observation Well shall include, at a minimum:

A) The information required by subparagraph (f)(6) below, for the existing or proposed well, and any additional information deemed necessary by the Director for public safety and the protection of USDWs;

B) A permit fee in the amount of three hundred dollars ($300.00), if the Storage Well or Observation Well is drilled, deepened, or re-entered;

C) The minimum financial assurance of thirty-five thousand dollars ($35,000) per well. The Director is authorized, however, to require additional financial assurance based on, but not limited to, how long a permit holder has operated in the State of Arkansas, environmental consideration of the well location, other factors impacting the cost of plugging the well and restoring the associated well site, and the compliance history of the permit holder. The required financial assurance shall be submitted in accordance with General Rule B-2;

D) A Form 1 Organizational Report in accordance with General Rule B-13;

E) An oath that the application is executed under penalty for perjury;

F) If the applicant is a corporation, limited liability company, limited liability partnership or other business entity, it must be incorporated, organized, or authorized to do business in the State of Arkansas. The applicant must state that by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to the jurisdiction of the Commission or to a hearing before the Commission, or in a court of competent jurisdiction in the State of Arkansas; and

G) If the applicant is an individual, partnership, or other entity that is not domiciled in the State of Arkansas, the applicant must be authorized to do business in the State of Arkansas. By filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to the jurisdiction of the Commission or to a hearing before the Commission, or in a court of competent jurisdiction in the State of Arkansas.

5) If the application does not contain all of the required information or documents, the Director shall notify the applicant in writing. The notification shall specify what additional information or documents are necessary for an evaluation of the application and shall state to the applicant that the application will be deemed denied unless the information or documents are submitted within sixty (60) days following the date of notification.

6) The application for a Storage Well shall include the following:

A) On a form prescribed by the Director, the applicant shall provide the name, address, phone, fax, and e-mail (if available) of the local or on-site supervisory or field personnel responsible for the Storage Well;

B) A survey plat of the location and ground elevation of the proposed Storage Well or existing well. The survey plat shall include all wells within ¼ mile of the proposed or existing well and the current well status of each well;

C) The name and the approximate top and bottom elevation, from sub-sea, of the formation (indicating the perforated or open hole interval) into which Natural Gas will be injected. If an existing well is to be converted, a geophysical log of the well shall be submitted showing the above information. For a proposed well, an induction log from a well in the immediate vicinity of the proposed disposal well shall be submitted; and

D) A well bore diagram of the proposed or existing well showing casing for the Storage Well, indicating from the well head to total depth of the well, all casings and cementing of casings, tubing and packer setting depth, and all perforations and or open hole intervals. If application is for an existing well, a cement bond log shall be submitted with the application, or if submitted after the application is filed, the cement bond log shall be submitted prior to commencement of operations as a condition of the permit. If a cement bond log must be run, it shall be witnessed by a Commission representative.

7) If the application does not satisfy the requirements of this rule, the application shall be denied. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination in accordance with General Rules A-2, A-3, and other applicable hearing procedures.

g) New Non-Storage Wells Drilled, Re-Entered or Deepened Through the Storage Reservoir

1) Any new well drilled, after the effective date of this rule, through the USR within a USF, for any purpose other than storage shall comply with the casing programs contained in (i)(1) below.

2) Any new well re-entered or deepened, after the effective date of this rule, through a USR within a USF, shall be evaluated for compliance with (i)(2) below. Wells not in compliance shall be reworked and cemented, in accordance with (i)(2), to achieve the necessary isolation of the USR.

3) Well plugging requirements of a non-storage well located within the USF area shall be the same as for a Storage Well as outlined in (k) below, and any other additional requirements in General Rule B-9.

h) Existing Non-Storage Wells

1) Any non-storage well penetrating a USR, in existence on or after the effective date of this rule, shall be evaluated to determine adequate isolation of the USR. The Director may require a cement bond log, cement evaluation log or other logs, to determine adequate isolation of the USR. Non-storage wells which the Director has determined do not provide adequate isolation of the USR, may be required by the Commission, after notice and hearing, to be reworked to properly isolate the USR.

2) All casing strings or liner strings run in any existing well, which extends through the USR, shall be cemented in accordance with (i)(2) below.

3) Well plugging requirements of a non-storage well located within the USF area shall be the same as for a Storage Well as outlined in subsection (k) below, and any other additional requirements in General Rule B-9.

i) Storage Well Construction, Operation, Maintenance and Decommissioning Requirements

1) All Storage Wells drilled after the effective date of this rule, for the purpose of Underground Storage, shall comply with the following requirements:

A) All casing used in Storage Wells shall meet American Petroleum Institute standards, shall be rated for the pressures to be encountered during the operational life of the well, and shall either be new casing or reconditioned casing of new quality;

B) All casing strings shall be centralized throughout the intervals to be cemented, and all casings shall be cemented to surface. Casing set through the USR shall have centralizers placed near the top and bottom of the USR;

C) All cement used for casing cement shall meet or exceed current American Petroleum Institute standards or recommended practices. Cement should be of the appropriate type and class of cement for the intended use and mixed to the

appropriate weight. Cement pumping pressures shall not exceed the fracture pressure of the USR. Cement slurry samples shall be taken and properly labeled and stored by the Storage Operator for further testing as necessary;

D) Surface casing shall be:

i) Set at a depth of one hundred (100) feet below any known USDW within ½ mile of the USF, or at a depth of five hundred (500) feet, whichever is greater, and

ii) Cemented with a minimum of one hundred fifty percent (150%) of the calculated annular volume to circulate cement to the surface;

E) All wells shall be completed with tubing and packer.

2) Any non-storage well converted for the purpose of underground storage shall comply with the following requirements:

A) The top of cement and the degree of bonding of the cement used to anchor the existing production casing or liner string shall be verified by cement bond log, cement evaluation log or other logs approved by the Director;

B) The injection of Natural Gas shall not result in the movement of Natural Gas or other fluids into a USDW, or other oil or Natural Gas reservoir;

C) New casing liners shall be cemented with sufficient volume to fill the annular space to the surface; and

D) All wells shall be completed with tubing and packer.

j) Mechanical Integrity Requirements for New and Existing Storage Wells:

1) Each Storage Operator of a Storage Well equipped with a tubing and packer completion, shall prove mechanical integrity of the well before placing it into service. Mechanical integrity shall be demonstrated by pressure testing the annulus to the permitted Storage Well injection pressure, with a minimum test pressure of five hundred (500) psig. Following successful demonstration of mechanical integrity, the Storage Well shall be re-tested at least every three (3) years.

2) Each Storage Operator of a Storage Well not equipped with a tubing and packer completion, shall prove mechanical integrity within thirty (30) days after the effective date of this rule. Mechanical integrity shall be demonstrated by setting a retrievable plug within the production casing at a point fifty (50) feet above the uppermost perforation, and pressure test the casing up to the permitted Storage Well maximum injection pressure, with a minimum test pressure of five hundred (500) psig. Following successful demonstration of mechanical integrity, the Storage Well shall be re-tested at least every five (5) years.

3) The pressure test shall be continued for thirty (30) minutes and shall not decrease by more than 10 percent (10%) of the initial pressure over the length of the test.

4) Upon request, the Director may approve alternate test methods, including tracer survey, temperature survey, gamma ray log, neutron log, noise log, casing inspection log or a

combination of these methods to demonstrate mechanical integrity. All mechanical integrity alternate test methods shall be witnessed by a Commission representative.

5) If a Storage Well fails to demonstrate or maintain mechanical integrity, the well shall be removed from service immediately. The Storage Operator shall notify the Commission's regional office within four (4) hours of any well that fails or loses mechanical integrity. The Storage Operator must take action to isolate the cause of the failure and demonstrate to the Director that the well does not pose a threat to a USDW or public safety.

6) Storage Wells which fail to demonstrate mechanical integrity shall be repaired within one hundred eighty (180) days, and successfully pass a mechanical integrity test or be plugged.

k) Monitoring and Reporting

1) Each Storage Well shall be monitored, on a weekly basis, for wellhead and casing annulus pressure. All monitoring records shall be retained by the Storage Operator for five (5) years and be available to Commission staff for review upon request.

2) The operator of the USF shall notify the Commission regional office of any potential leak discovered within four (4) hours of the discovery of the leak.

3) The Storage Operator shall file, on a form prescribed by the Director, the monthly volumes of Natural Gas injected and withdrawn from the USR.

4) Prior to performing any well servicing activity, cementing, or any wireline logging activities, the Storage Operator of the USF shall provide notice to the Commission regional office where the Storage Well is located so as to allow Commission staff to be present to observe the activity. Any well servicing which requires the resetting of the packer shall require that an internal mechanical integrity test be conducted in accordance with subparagraph (j) above, prior to re-commencement of injection.

l) Storage Well Abandonment

1) A well plugging plan shall be filed with the Commission regional office thirty (30) days prior to any planned well plugging activity. All Storage Wells shall be plugged in a manner to permanently isolate the USR from all other oil and Natural Gas reservoirs and any existing USDWs within the USF area.

2) The minimum well plugging requirements are as follows:

A) The Storage Well shall be plugged as follows:

i) Utilizing a cement retainer set fifty (50) feet above the top perforation in the Storage Well, adequate cement shall be pushed into the USR to prevent pressure channeling while the subsequent Storage Well cement plug is setting.

ii) Following completion of the Storage Well cementing operation, an additional one-hundred fifty (150) feet of cement shall be placed on top of the cement retainer utilized in the Storage Well cementing operation.

B) If cement is not present on the backside of the production casing at the required plug depths specified in A) above, cement shall be placed on the backside of the production casing during the Storage Well plugging operations.

C) Following the completion of the Storage Well plugging operation, a pressure test shall be run on the casing to determine cement integrity. If the casing fails this test, it shall be repaired and retested prior to the subsequent plugs being set as required in accordance with D) below.

D) Subsequent plugs shall be set to satisfy the requirements of Rule B-9.

E) If wellbore conditions preclude the setting of a cement retainer for the Storage Well plugging operation, an alternative plugging method may be approved or required by the Director. In determining whether to approve an alternative plugging method, the Director shall consider the time and cost associated with the alternative plugging method, the potential for damage to USDWs or other oil or gas reservoirs, the depth of the reservoir in relation to the depth of the USDWs, well construction characteristics, and the potential for upward migration of wellbore fluids into a USDW.

m) Decommissioning of Underground Storage Facility

1) The Storage Operator of a USF shall file a plan for decommissioning a USF six (6) months prior to commencement of the decommissioning activity. The plan shall include:

A) The anticipated date of commencement and final completion of the decommissioning activities;

B) A detailed plan and timeline for the activities, including well plugging operations, equipment removal from the well sites and all central or remote facilities in the USF, abandonment of pipelines, and restoration of property as necessary;

C) The names and contact information for the persons, consultants, contractors and firms used in the decommissioning activity; and

D) The anticipated reservoir pressure at abandonment.

2) The Storage Operator shall file a monthly report on the 15th of each month indicating the work completed for the preceding month during the decommissioning activity.

3) At the completion of the decommissioning, the Storage Operator shall submit a final decommissioning report and termination of storage operations. Upon receipt of the final report and completion of a final inspection of the USF, and all wells and facilities by the Commission staff, the Storage Operator's Certificate of Storage shall be terminated.

n) Federal Requirements

1) The USF is additionally subject to and required to be in compliance with the following federal requirements, unless the following federal requirements are less stringent than any other applicable requirements of General Rule D-23.

2) Required federal requirements are as follows:

A) Operation and maintenance requirements in Federal Regulations 49 CFR, Part 192, as amended;

B) Applicable enforcement provisions of Federal Regulation 49 CFR, Part 190, as amended;

C) Applicable incident and other reporting requirements contained in Federal Regulation 49 CFR, Part 191, as amended (and all such reports shall be submitted to the Oil and Gas Commission); and

D) All Storage Operators of a USF shall be subject to the applicable drug and alcohol testing requirements contained in Federal Regulation 49 CFR, Part 199, as amended.

(Source: new rule December 21, 2020)

GENERAL RULE E - TRANSPORTATION

RULE E-1: PIPE LINES, PURCHASERS AND TRANSPORTERS

(A) No carrier by pipe line and no gathering system shall transport oil from any lease or wells if the said pipe line or gathering system has reason to believe the owner or operator of said lease or wells to which it is connected has violated any rule or order of the Commission or any conservation laws of the State with reference to oil and gas.

(B) No pipe line company shall transport oil from any gathering system which the said pipe line company has reason to believe has violated any rule or order of the Commission or any conservation law of this state with reference to oil and gas.

It shall be the duty of the pipe line company to suspend transportation of any oil from said gathering system until such time as such pipe line company is notified in writing by the agent of the Commission that the violation on the part of the gathering system has been discontinued and that the gathering system is complying with the rules and orders of the Commission and the conservation laws of the State of Arkansas.

(C) In order to carry out the spirit and purposes of this and other rules tending to provide orderly production of crude oil without waste and to give equal opportunity for marketing oil to all operators bringing wells into production in said field, all pipe line companies are hereby directed to make connection of their lines to the lease tanks on properties or leases in rotation as wells are completed, regardless of ownership. Connections shall be accepted and taken by the pipe line which by geographical location and least expense is the logical connection unless some other line is willing to accept the same. All wells which are at the present time unconnected shall be given connection by the pipeline to which the same are or may be allocated before the owners of such pipe lines make connections to their own wells or wells of affiliated companies.

(Source: 1992 rule book)

RULE E-2: REPORTS FROM OIL PIPE LINES, TRANSPORTERS AND STORERS

Each transporter of oil within the State of Arkansas shall furnish for each calendar month a "Transporter's and Storer's Monthly Report", containing complete information and data indicated by such form respecting stocks of oil on hand and all movements of oil by pipe line within the State of Arkansas and all movements of oil by watercraft, or by trucks or other conveyances except railroads, from leases to storers or refiners; between transporters within the State; between storers within the State; between refiners within the State; and between storers and refiners within the State.

Each storer of oil within the State of Arkansas shall furnish for each calendar month a "Transporter's and Storer's Monthly Report", containing complete information and data indicated by such form respecting the storage of oil within the State of Arkansas.

The transporters and storers reports for each month shall be prepared and filed according to instructions on the form, on or before the 15th day of the next succeeding month.

(Source: 1992 rule book)

RULE E-3: EXPLORATION AND PRODUCTION FLUID GATHERING, HANDLING AND TRANSPORTATION

a) Definitions

1) "Class II Fluids" means:

A) Produced water and/or other fluids brought to the surface in connection with drilling, completion or fracture treatments, workover or recompletion and plugging of oil, natural gas, Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations, or

B) Produced water and/or other fluids from A) above, which prior to re-injection have been used on site for purposes integrally associated with well drilling, completion or fracture treatments, workover or recompletions or plugging oil, natural gas, Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; natural gas storage operations; or chemically treated or altered to the extent necessary to make them usable for purposes integrally related to well drilling, completion, workover or recompletions or plugging oil, natural gas, Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; natural gas storage operations, or commingled with fluid wastes resulting from fluid treatments outlined above, provided the commingled fluid wastes do not constitute a hazardous waste under the Resource Conservation and Recovery Act.

2) "Exploration and Production Fluid" means crude oil bottom sediments and all Class II fluids, to the extent those fluids are now or hereafter exempt from the provisions of Subtitle C of the Federal Resource Conservation Recovery Act of 1976.

3) "Exploration and Production Fluid Transportation System" means any motor vehicle licensed for highway use on a public highway or used on a public highway, that is equipped for either carrying or pulling a Transportation Tank containing Exploration and Production Fluids, from the point of any fluid generation or collection site to any subsequent off-site storage facility, surface disposal facility or an injection well disposal facility.

4) "Exploration and Production Fluid Transporter" means an operator of an Exploration and Production Fluid Transportation System.

5) "Transportation Tank" means an assembly, compartment, tank or other container that is used for transporting or delivering Exploration and Production Fluid.

b) No person shall operate an Exploration and Production Fluid Transportation System without an Exploration and Production Fluid Transportation System permit. Application for which shall be made on forms prescribed by the Director. The application shall be executed under penalties of perjury, and accompanied by an Exploration and Production Fluid Transportation System permit fee in the amount specified below.

c) If the application does not contain all of the required information or documents, the Director or his or her designee shall notify the applicant in writing. The notification shall specify the additional information or documents necessary to process the application, and shall advise the

applicant that the application will be deemed denied unless the additional information or documents are submitted within 30 days following the date of notification.

d) The application shall, at a minimum, include:

1) A permit fee of $100.00 per Transportation Tank.

2) The name, address, and business and emergency telephone numbers of the proposed Exploration and Production Fluid Transporter, including Arkansas contact information if the transporter is located outside of the state of Arkansas.

3) A brief description of the number and type of Transportation Tanks to be used in the system; specifying whether Transportation Tanks will be owned, leased or otherwise arranged for and including tank capacity and a manufacturers serial number or other identifying number for Transportation Tank.

4) An Entity Organizational Report on a form prescribed by the Director.

e) If the applicant satisfies all requirements of this rule, the Director shall issue an Exploration and Production Fluid Transportation System permit and permit sticker for each Transportation Tank. The Exploration and Production Fluid Transportation System permit shall be kept in the Arkansas office of the Exploration and Production Fluid Transportation System permit holder. The permit sticker shall be affixed to the back of the Transportation Tank and shall be kept visible and readable at all times.

f) Exploration and Production Fluid Transportation System permits are not transferable.

g) Exploration and Production Fluid Transportation System permits shall be renewed annually on July 1 of each year, commencing on July 1, 2010; and Amended applications, including any additional permit fees, are required to be submitted within thirty (30) days of the addition of any Transportation Tanks to the Exploration and Production Fluid Transportation System.

h) Exploration and Production Fluid Transportation System recordkeeping requirements:

1) Each Exploration and Production Fluid Transportation System permit holder shall maintain a record of all Exploration and Production Fluids received, transported, delivered or disposed of, which shall include the well lease or unit name, well or facility operator (fluid generator), the date received, the amount per pick up, type of fluid, and the name and location of the permitted off-site temporary storage facility, permitted surface disposal facility or permitted injection well disposal facility.

2) Records shall be maintained a minimum of three (3) years at the Arkansas office of the Exploration and Production Fluid Transportation System permit holder, and shall be made available to commission staff for inspection during normal business hours.

i) Exploration and Production Fluid Transportation System operating requirements:

1) All Transportation Tanks and associated piping and valves must be kept in leak free condition.

2) Exploration and Production Fluid Transporters shall only transport Exploration and Production Fluid to a permitted well for re-use in the well drilling or well completion process, a permitted off-site temporary storage facility, a permitted surface disposal

facility or a permitted injection well disposal facility. Exploration and Production Fluid shall not be released or discharged onto the ground surface or into Waters of the State, unless otherwise authorized by the Arkansas Department of Environmental Quality.

3) All Exploration and Production Fluids stored at a permitted temporary storage facility shall be contained in tanks or permitted temporary storage pits.

4) Exploration and Production Fluid shall not be commingled or blended with non-exempt waste (such as used motor or compressor oil) under Subtitle C of the Federal Resource Conservation and Recovery Act of 1976.

5) All Transportation Tanks shall contain the name and phone number of the Exploration and Production Fluid Transporter in a legible manner.

j) No person shall engage, employ or contract with any other person except a permitted Exploration and Production Fluid Transporter to transport Exploration and Production Fluids.

k) Failure to comply with provisions of this rule may result in revocation of the Exploration and Production Fluid Transportation System permit, and/or the assessment of civil penalties in accordance with General Rule A-5.

(Source: new rule January 22, 2009; amended October 24, 2009)

GENERAL RULE F - PROCESSING

RULE F-1: REPEALED

Rule Repealed Effective October 19, 2018 in accordance with Act 781 of 2017

RULE F-2: REFINERY REPORTS

Each refiner of oil within the State of Arkansas shall furnish for each calendar month a "Refiner's Monthly Report", containing the information and data indicated by such form, respecting oil and products involved in such refiner's operations during each month. Such report for each month shall be prepared and filed according to instructions on the form, on or before the 15th day of the next succeeding month.

(Source: 1992 rule book)

RULE F-3: GASOLINE PLANT REPORTS

Each operator of a gasoline plant, cycling plant or any other plant at which gasoline, butane, propane condensate, kerosene, oil, or other liquid products are extracted from natural gas within the State of Arkansas, shall furnish for each calendar month a "Monthly Gasoline or Other Extraction Plant Monthly Report", containing the information indicated by such form respecting natural gas and products involved in the operation of each plant during each month.

Such reports for each month shall be prepared and filed according to instructions on the form on or before the 15th day of the next succeeding month.

(Source: 1992 rule book)

GENERAL RULE G - ABANDONED AND ORPHAN WELL PLUGGING PROGRAM

RULE G-1: ABANDONED OR LEAKING WELL AND WELL SITE REMEDIATION

a) This rule is applicable for the following types of wells:

1) oil and gas production wells,

2) water supply wells used in enhanced oil and gas recovery projects,

3) UIC Class II Disposal and Class II Commercial Disposal wells, and

4) UIC Class II water injection wells used in enhanced oil and gas recovery projects.

b) Definitions

1) "Abandoned Well" means:

A) an oil and gas production well which has not produced for over 2 years; or

B) a UIC Class II saltwater disposal or UIC Class II water injection well which is no longer used due to the plugging of all the wells on the lease or unit or for which and agreement to continue use of the well has not been granted by the lease holder, or

C) a well for which the underlying lease has been released in writing by the lessee or has been declared forfeited or invalid by a court order, and such order is final and the appeal period has lapsed; and the lessor states in writing that the lessor has not leased out the oil and gas working interest to any other person and does not intend to so lease, and that the lessor does not intend to operate the well, and that the lessor desires that the well be plugged; or

D) a well owned or operated by a Permit Holder who has made no payment by March 1 of a current annual well fee assessment in accordance with Ark Code Ann. §15-71-116; or

E) a well that has been ordered to be plugged by the Commission and the Permit Holder has failed to do so within the time frame specified in the Commission Order; or

F) a well site which has not been properly restored following the completion of well plugging activities.

2) "Well Site Equipment" means the equipment, including but not limited to an associated tank battery, production and injection facility equipment, hydrocarbons from the well that are stored in tanks located on the lease, and hydrocarbons recovered during the plugging operation.

3) "Well Site" means the area around and near the well, including any associated pits, crude oil or produced water storage tanks or other related production facility equipment, such as injection pumps, compressors or gas processing equipment.

4) "Director" means the Oil and Gas Commission Director of Production and Conservation.

5) "Leaking Well" means a well drilled for the exploration, development, storage or production of oil or gas, or for injection, saltwater disposal, saltwater source, observation, and geological or structure test which is leaking salt water, oil, gas, or other deleterious substance into any fresh water formation or onto the surface of the land in the vicinity of the well.

6) "Well Site Restoration" means remediation of a well site, including but not limited to the following activities: an emergency clean-up of spilled crude oil or saltwater; remediation of conditions endangering the public health or safety, or contaminating or potentially contaminating surface waters, groundwater, or the surface of the land; work to repair or contain leaks of produced fluids from wells, production or injection equipment, pits or other containment structures, which are contaminating or potentially contaminating surface waters, groundwaters or the surface of the land; or a repairing a well leaking natural gas or hydrogen sulfide gas endangering or potentially endangering public safety or creating a potential a fire hazard.

c) If the Director finds, upon inspection and/or review of Commission records, that a well drilled for the exploration, development, storage or production of oil or gas, or for injection, saltwater disposal, saltwater source, observation, and geological or structure test, may be abandoned; well site restoration has not been completed; is a leaking well; or the well or well site creates an imminent danger to the health or safety of the public, the Director may schedule a hearing, in accordance with established procedures.

d) If after notice and a hearing, the Commission finds that a well drilled for the exploration, development, storage or production of oil or gas, or for injection, saltwater disposal, saltwater source, observation, a geological or structure test, may be abandoned; well site restoration has not completed; is a leaking well; or the well or well site creates an imminent danger to the health or safety of the public; the Commission shall issue an order requiring the Permit Holder to properly plug, re-plug, repair, or restore so as to remedy the situation.

e) If the Permit Holder fails to properly plug, re-plug, repair, or restore so as to remedy the situation within 30 days from the time frame prescribed by the Commission order, the abandoned well or well site; leaking well; a well or well site that creates an imminent danger to the health or safety of the public; or a well site restoration has not been completed, the well or well site shall be subject to the provisions of this Rule.

f) The Director may then authorize any person to enter upon the land and properly plug, re-plug, repair, or restore so as to remedy the situation. The Director may dispose of all well site equipment and hydrocarbons, to offset the costs of properly plugging, re-plugging, repairing, or restoring so as to remedy the situation. Proceeds from any public sale, auction or private sale of all well site equipment or hydrocarbons shall be deposited into the Plugging Fund or used to offset plugging costs. All work completed under this rule shall be paid with funds from the Abandoned and Orphan Well Plugging Fund.

g) The Permit Holder shall reimburse the Commission for all costs expended to remedy the situation. All payments shall be by cashier's checks or money order, and shall be deposited in the Abandoned and Orphaned Well Plugging Fund. Failure to reimburse the Commission will result in the initiation of Commission enforcement action to recover the expended funds. Prior to repayment of all expended funds, the Permit Holder shall not be permitted to operate any other existing wells in the Permit Holder's name. Upon repayment and prior to being permitted to

operate any wells, the Permit Holder may be required to post additional bond, as determined by the Director in accordance with General Rule B-2, to insure against the plugging of future abandoned wells not plugged by the Permit Holder.

(Source: new rule April 13, 2008; amended November 26, 2009)

RULE G-2: PLUGGING OF ORPHAN WELLS

a) Definitions:

1) "Orphan Well" means a well for which a Permit Holder can not be located, there is no record the well is covered by a Commission required bond by the last known permit holder of record, and no fees have ever been paid on the well in accordance with Ark. Code Ann. § 15-71-110.

2) "Well Site Equipment" means the equipment, including but not limited to an associated tank battery, production and injection facility equipment, hydrocarbons from the well that are stored in tanks located on the lease, and hydrocarbons recovered during the plugging operation

3) "Well Site" means the area around and near the well, including any associated pits, crude oil or produced water storage tanks or other related production facility equipment, such as injection pumps, compressors or gas processing equipment.

4) "Director" means the Oil and Gas Commission Director of Production and Conservation.

b) If after review of the Commission records, the Director determines a well or well site to be orphaned, that well or well site may be administratively determined to be eligible for plugging, without the need for a hearing. Following designation as an orphaned well or well site, the Director may elect to properly plug, re-plug, or restore so as to remedy the situation, and authorize any person to enter upon the land properly plug, re-plug, or restore so as to remedy the situation.

c) All work completed under this rule shall be paid with funds from the Abandoned and Orphan Well Plugging Fund. Additionally, the Director may dispose of all well site equipment and hydrocarbons, to offset the cost of the well plugging and well site restoration operations. Proceeds from any public sale, auction or private sale of all well site equipment or hydrocarbons shall be deposited into the Plugging Fund or used to offset plugging costs.

(Source: new rule April 13, 2008)

RULE G-3: TRANSFER OF WELLS IN THE ABANDONED AND ORPHANED WELL PLUGGING PROGRAM

a) Definitions

1) "Well" as used in this Rule (G-3) shall only mean wells that are abandoned as defined in General Rule G-1 (a) (1), or orphaned as defined in General Rule G-2 (a) (1).

2) "Commission" means the Arkansas Oil and Gas Commission.

3) "Director" means the Director of Production and Conservation.

b) When a transfer request is received, on a form prescribed by the Director, for a well, the following documentation must be submitted by the proposed new Permit Holder:

1) a signed new base lease properly recorded in the county where the well is located; or

2) an affidavit stating a new base lease has been obtained and properly recorded in the county where the well is located;

c) Upon review and acceptance of the transfer request, and prior to approval of the transfer request, the proposed new Permit Holder shall:

1) pay a salvage value for the downhole well equipment as follows:

A) $500 per well for wells less than 3000 feet in depth; and

B) $1000 per well for wells equal to or greater than 3000 feet in depth; and

2) pay a salvage value for the tanks, pumping units, and other related equipment, as determined by submission of 2 independent salvage value estimates from commercial salvage oil and gas production equipment dealers and approved by the Director or his or her designee;

3) pay the fair market value per barrel, to be determined at the time of the transfer approval, for all oil fluids (hydrocarbons) stored on the lease or unit: and

4) if applicable, provide financial assurance in accordance with General Rule B-2 and file all other required organizational and registration forms.

d) All payments shall be by cashier's checks or money order, payable to the Commission, and shall be deposited in the Abandoned and Orphaned Well Plugging Fund.

e) The Director has sole discretion to approve or deny requests for transfer of the well. If, upon review of a transfer request for the well, the Director determines that property rights, environmental or public safety and welfare concerns will be advanced through plugging the well, the transfer request may be denied.

(Source: new rule April 13, 2008)

GENERAL RULE H - CLASS II UIC WELLS

RULE H-1: CLASS II DISPOSAL AND CLASS II COMMERCIAL DISPOSAL WELL PERMIT APPLICATION PROCEDURES

a) Definitions:

1) "Class II Disposal Well"-- means:

A) A permitted Class II well in which Class II Fluids are injected into zones not productive of oil and gas, and brine used to produce bromine, within the field boundary established by an order of the Commission for the production of liquid hydrocarbons or brine used to produce bromine, where the well is located or will be located, for the purpose of disposal of those fluids; or

B) A permitted Class II well in which Class II Fluids are injected into a zone or zones which are not commercially productive of dry gas, within the same common source of supply, where the well is located or will be located, for the purpose of disposal of those fluids."

2) "Class II Commercial Disposal Well"-- means a permitted Class II well in which Class II Fluids are injected, for which the Permit Holder receives deliveries of Class II Fluids by tank truck from multiple oil and gas well operators, and either charges a fee at the disposal well facility or purchases the Class II Fluids at the source for subsequent transport to the disposal well facility for the specific purpose of disposal of the delivered Class II Fluids.

3) "Class II Enhanced Oil Recovery Injection Well (EOR Well)" means a permitted Class II well into which Class II Fluids are injected into zones productive of oil and gas contained within an enhanced oil recovery unit established, by an order of the Commission, for the production of liquid hydrocarbons.

4) "Class II Fluids" means:

A) Produced water and/or other fluids brought to the surface in connection with: i) drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells; ii) Class II wells that are required to be permitted as water supply wells by the Commission; iii) enhanced recovery operations; or iv) natural gas storage operations; or

B) Produced water and/or other fluids from (A) above, which prior to re-injection have been used on site for purposes integrally associated to oil and natural gas well drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells; Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations, or chemically treated or altered to the extent necessary to make them usable for purposes integrally related to oil and natural gas well drilling, completion, workover and plugging, oil and gas production, enhanced recovery operations, or natural gas storage operations, or commingled with fluid wastes resulting from fluid treatments outlined above, and including any other exempted oil and gas related fluids under the Resource Conservation and Recovery Act, provided the commingled fluid wastes do not

constitute a hazardous waste under the Resource Conservation and Recovery Act; or

C) Waste fluids from gas plants (including filter backwash, precipitated sludge, iron sponge, hydrogen sulfide and scrubber liquid) which are an integral part of oil and gas production operations; and waste fluids from gas dehydration plants (including glycol-based compounds and filter backwash), unless the gas plant or gas dehydration plant wastes are classified as hazardous under the federal Resource Conservation and Recovery Act.

5) "Class V Brine Disposal Well" means a permitted Class V well, located within an established unit (voluntary or Commission established) created for the production of brine used to produce bromine and/or other chemical and mineral constituents of economic value, into which spent brine, following processing and removal of useable constituents, is injected into the zone of production for the purpose of disposal.

6) "Confining layer" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. It is composed of rock layers that are impermeable or distinctly less permeable than the injection zone beneath it. There may be multiple confining layers above an injection zone.

7) "Disposal system" means a system for disposing of Class II Fluids.

8) "High volume disposal system" means a disposal system with an on-site storage capacity of greater than 1000 barrels of Class II Fluids.

9) "Permit Holder" means the entity or person to whom the permit is issued and who is responsible for all regulatory requirements relative to the Class II Disposal, Class II Commercial Disposal, Class II EOR, or Class V Brine Disposal Wells.

10) "Spent Brine Fluid" means brine fluid, which prior to re-injection, was produced for the purpose of processing the brine fluid to remove bromine and other chemical and mineral constituents of economic value from the brine fluid.

11) "UIC Well" means any of the Class II Disposal, Class II Commercial Disposal, Class II EOR, or Class V Brine Disposal Well types.

12) "USDW" means Underground Source of Drinking Water which is defined in Title 40, Code of Federal Regulations (40 CFR) Section 144.3, as an aquifer or its portion which:

A) Supplies any public water system (see 40 CFR); or

B) Contains a sufficient quantity of groundwater to supply a public water system (see 40 CFR) and currently supplies drinking water for human consumption; or

C) Contains fewer than 10,000 mg/l total dissolved solids (see 40 CFR); and

D) Which is not an exempted aquifer (see 40 CFR).

b) No person shall drill, deepen, re-enter, recomplete or operate any UIC Well or inject into any UIC Well, without the applicable permits, except as specified in subparagraph b) 1) below, from the Commission, application for which shall be made on forms prescribed by the Director. Permits

are valid only for the Permit Holder stated on the permit, and shall remain valid only with ongoing compliance with established operating requirements specified in General Rule H-2 or H-3, except that permits to drill, deepen, or re-enter shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed one (1) year from the date of commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit, at which time the well shall be plugged, injection casing set, or a new permit application, along with a new permit fee and plat, must be filed.

1) Authority to conduct an injectivity test, step rate test or trial injection test prior to, or after the issuance of a permit may be approved as follows:

A) An injectivity test, step rate test or trial injection test of less than twelve (12) hours duration may be approved by the Director upon review of the well construction to determine well mechanical integrity for the protection of the USDW's and oil and gas resources during the test. The Director shall establish the protective parameters of the test, require the submittal of any information or test data deemed necessary and may require the witnessing by Commission staff of the test.

B) An Applicant may request approval from the Commission, by filing an application in accordance with General A-2 and A-3 and other applicable hearing procedures, of an injectivity test, step rate test or trial injection test of twelve (12) hours or more in duration.

2) No UIC Well may be drilled at a surface location other than that specified on the permit, except that if a permit holder has commenced drilling operations and the UIC Well is lost due to adverse drilling conditions prior to surface casing being set, the permit holder may request an amendment of the permit without a fee for the new location, provided the UIC Well remains on the same surface owners property where the UIC Well was originally permitted and all other aspects of the permit request remain the same. Movement of the UIC Well location off the original surface owners' property, or after surface casing has been set, will require the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

3) Permits to recomplete or operate shall automatically expire one year from the date of issuance, unless commencement of the operations authorized by the permit has occurred, or a new permit application, along with a new permit fee has been filed.

4) Upon issuance of a permit, a copy of the permit shall be displayed at the site where the UIC Well is being drilled for review by Commission staff.

5) Permits to drill, deepen, or re-enter a UIC Well may only be issued if the location complies with General Rule B-3.

c) Failure to comply with the operating requirements in General Rule H-2 or H-3 may result in revocation of the UIC Well permit in accordance with subparagraph s) below.

d) All surface facilities, included but not limited to storage tanks, flowlines, injection equipment, related to UIC Wells shall be regulated as follows:

1) Any surface facility associated with a Class II Disposal Well which is not associated with a High Volume Disposal System shall be maintained and operated in accordance with AOGC General Rule B-26.

2) Any surface facility associated with a Class II Commercial Disposal Well or a Class II Disposal Well that is associated with a High Volume Disposal System shall be permitted and operated in accordance with Arkansas Department of Environmental Quality requirements specified in PC&E Rule 1.

3) Any surface facility associated with a Class II EOR and Class V Brine Disposal Well shall be maintained and operated in accordance with AOGC General Rule B-26.

e) The application to drill, deepen, re-enter, recomplete or operate a UIC Well shall include at a minimum:

1) The information required by subparagraph (h) below, for the existing or proposed UIC Well and any additional information deemed necessary by the Director for the protection of USDWs; and

2) Accompanied by a drilling permit fee in the amount of $300.00 if the UIC Well is drilled, deepened, or re-entered; and

3) Accompanied by a non-refundable application fee of $100.00 for a Class II Disposal, Class II EOR, or Class V Brine Disposal Well or $500.00 for a Class II Commercial Disposal Well to recomplete or operate the UIC Well; and

4) Accompanied by the required financial assurance in accordance with General Rule B-2; and

5) Accompanied by a Form 1 Organizational Report in accordance with General Rule B-13; and

6) Be executed under penalties of perjury; and

7) If the applicant is a corporation, limited liability company, limited liability partnership or other business entity, it must be incorporated, organized, or authorized to do business in the State of Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

8) If the applicant is an individual, partnership, or other entity that is not a resident of Arkansas, the applicant must be authorized to do business in Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

9) Proof that the UIC Well location complies with General Rule B-3; and

10) If the application is for a Class II Disposal Well associated with a Disposal System that is not a High Volume Disposal System, (i) a plat showing the location and proposed or existing configuration of the storage tank disposal facility, (ii) the total disposal storage capacity of Class II Fluids at the facility, and (iii) a list of the production wells utilizing the Class II Disposal Well.

f) No person shall inject into USDWs or be issued a permit to inject into USDWs unless an aquifer exemption has been granted in accordance with US Environmental Protection Agency procedures.

g) Unless otherwise approved by the Commission, no person shall inject into a UIC well which does not have at a minimum, five hundred (500) feet for a Class II Disposal Well or seven hundred-fifty (750) feet for a Class II Commercial Disposal or Class V Brine Disposal Well, of confining layers between the base of the lowermost USDWs and the top of the injection interval, with no individual confining layer being less than 50 feet in thickness. A lesser amount of confining layer(s) may be approved, provided the Applicant provides substantial information as to the integrity of the confining layers to inhibit the upward migration of the injection fluids so as not to endanger the lowermost USDW in the area of the UIC well.

h) If the application does not contain all of the required information or documents, the Director shall notify the Applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application and shall advise the Applicant that the application will be deemed denied unless the information or documents are submitted within sixty (60) days following the date of notification.

i) Applications for a Class II Disposal Well shall contain the names of all permit holders who are to utilize the proposed disposal well.

j) Contents of Application

1) A specification as to the type of UIC Well being permitted.

2) If the application is for a Class II Disposal or Class II Commercial Disposal Well, the Applicant shall provide the name, address, phone, fax and e-mail (if available) of the local or on-site supervisory or field personnel responsible for the disposal well.

3) If the Class II Disposal Well is not located within the boundaries of an operating oil and gas leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement or an affidavit of a surface use agreement, indicating the Applicant’s right to drill and to operate the proposed Class II Disposal Well. If the Class II Disposal Well is located within the boundaries of an operating oil and gas leasehold or drilling unit, and the Applicant is someone other than the operator of the leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement, or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed Class II Disposal Well. If the well is a Class II Commercial Disposal Well, the Applicant shall provide documentation, in the form of a surface use agreement, or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed Class II Commercial Disposal Well.

4) A survey plat of the location and ground elevation of the proposed UIC Well or if the application is for a previously permitted well, the well name and permit number of the previously permitted well. A new survey is not required for a well to be converted or deepened well or a plugged well to be re-entered, if the original well location was surveyed, a copy of which shall be submitted with the application.

5) The name, geologic description and the approximate top and bottom elevation, from sub-sea, of the formation (indicating the perforated or open hole interval) into which fluid will be injected and the geologic description and top and bottom elevation, from sub-sea, of the above confining layers, in the proposed or previously permitted UIC Well. If a

previously permitted well is to be converted, a geophysical log of the previously permitted well shall be submitted showing the above information. For a proposed well, an induction log from a well in the immediate vicinity of the proposed UIC Well shall be submitted. If the geologic name of the interval is unclear include any additional geological evidence such as a cross section, structure or isopach map that may be necessary to adequately define the proposed injection interval.

6) A well bore diagram of the proposed or previously permitted well showing from the well head to total depth of the well, all casings and cementing of casings, any obstructions within well, all plugs set, tubing and packer setting depth, and all perforations and or open hole intervals. If application is for a previously permitted well, a cement bond log (CBL) shall be submitted with the application, or if submitted after the application is filed, the CBL shall be submitted prior to commencement of operations as a condition of the permit.

7) The proposed daily amounts to be injected, the source and the type of fluid to be injected, and standard laboratory report from an accredited laboratory reporting the laboratory results of a representative sample of the proposed fluids to be injected, for the following parameters: chloride, pH, specific gravity, total dissolved solids (TDS) and total percent hydrocarbon (TPH). The sample shall be obtained and analyzed no earlier than one hundred-eighty (180) days prior to the date of filing of the application and analyzed in a timely fashion after collection.

8) The maximum injection pressure.

A) The Director shall determine the maximum permitted injected pressure, measured at the wellhead, by multiplying the results of the formula below by ninety percent (90%):

i) A maximum fracture gradient not to exceed 1.1 psi/ft (x) depth to injection formation (-) weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette Miller, Nevada, Ouachita, and Union counties for injection into formations below the Midway Shale Formation; or

ii) A maximum fracture gradient not to exceed 1.0 psi/ft **(**x**)** depth to injection formation (-) weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in all other counties for injection into formations below the Fayetteville Shale Formation in the areas covered by General Rule B-43 (c) and (d), General Rule B-44, and the portions of Franklin, Logan, Scott, Sebastian, and Yell Counties not covered by General Rule B-44; or

iii) A maximum fracture gradient not to exceed 0.73 psi/ft **(x)** depth to injection formation (-) weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss for all other formations and/or counties.

The following calculation is included only as an example, and for informational and demonstrative purposes only. For purposes of this example, assume the well is in Columbia County, the total depth to the injection formation is 2,500 feet, the specific gravity is 1.085, and the injection tubing friction loss is

250 psi. Using the formula provided above, the maximum permitted injection pressure for the well would be 1,642 psig, calculated as follows:

Step 1: 0.9 x [(1.1 psi/ft x 2500 ft) – [0.433psi/ft x 2500 ft) x 1.085 (specific gravity)] + 250 tubing friction loss]

Step 2: 0.9 x [2750 psi – 1175 + 250 tubing friction loss]

Step 3: 0.9 x [1825]

Step 4: Result = 1642 psig

B) An Applicant may request an increase in the maximum injection pressure specified in subparagraph j) 8) A) above, or appeal a Director's decision to issue a permit utilizing a fracture gradient less than the maximum fracture gradient specified in subparagraph j) 8) A) above, by filing an application in accordance with General A-2, A-3 and other applicable hearing procedures. Any increase in the maximum injection pressure may be granted if the Applicant presents sufficient evidence to justify the requested increased injection pressure will not initiate or propagate fractures in the overlying confining layer(s) that could enable the injection fluid or the fluid in the injection interval to leave the permitted injection intervals or cause movement of the injection fluid or formation fluids into USDWs.

9) A map showing:

A) The surveyed location of the UIC Well proposed to be drilled, deepened or converted, showing distances to the nearest property or lease lines; and

B) The location of all known plugged and unplugged wells, which penetrate the proposed injection interval, within the 1/2 mile radius from the proposed disposal well, and showing the status of each well as producing, shut-in, disposal, enhanced recovery, plugged and abandoned, or other status.

10) The Applicant shall submit evidence, where available, that all plugged and unplugged wells which penetrate the injection formation, within the ½ mile radius shown on the above plat in subparagraph j) 9) B), contain an adequate amount of cement and are constructed or plugged in a manner which will prevent the injection fluid and the fluid in the injection formation from entering USDWs. The types of evidence that will be considered acceptable include, but are not limited to: well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs, and plugging records.

11) The Applicant shall submit evidence and/or information showing that the proposed injection interval or formation is not a USDW.

12) The Applicant shall submit information as to the depth (subsea) of the fresh water supply in the nearest known private water well and in the nearest known public water system water well.

13) If the application is for a Class II Commercial Disposal Well, a listing of all previous and current violations of any statute, rule, permit condition, or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution Control and

Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities.

k) Notice of the application shall be given by the Applicant by one (1) publication in a legal newspaper having a general circulation in the county, or in each county, if there shall be more than one, in which the one-half mile radius from the proposed disposal well is situated, and by mailing via certified mail, FedEx, UPS, or other method that provides proof of mailing and delivery, a copy of the application to each permit holder of all permitted, drilling or producing wells within a one-half mile radius of the proposed disposal well. Such notice shall be published or mailed no more than thirty (30) days, prior to the date on which the application is filed with the Commission. The cost of such notice and mailing of the application shall be paid for by the Applicant. Attached to the application shall be evidence that the application was mailed or sent as required and a proof of publication of the application from the newspaper.

l) If notice is for a Class II Commercial Disposal Well, in addition to compliance with subparagraph i) above, the Class II Commercial Disposal Well application shall also be sent via certified mail, FedEx, or UPS to the County Judge of the county where the well is located and to the landowner (surface owner) where the well is located. In addition, the public notice should be large font and surrounded by a printed border to highlight the published notice.

m) Objections received by the Director, must be received by the Director within fifteen (15) days after the publication date of the notice and the date of mailing or sending to all parties specified in subparagraphs k) and l) above.

n) If an objection is received the application shall be deemed denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

o) If an objection is not received by the Director and the application is deemed complete, the permit shall be issued following the required notice period specified in subparagraph k) above, unless the Director deems it necessary, for the purpose of protecting USDWs or oil and gas resources, that the application may be referred to the Commission for determination, and no additional filing fee is required from the applicant.

p) If the application does not satisfy the requirements of this Rule, the application shall be denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

q) If the Applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, unless:

1) The Applicant has falsified or otherwise misstated any material information on or relative to the permit application; or

2) For purposes of Class II Commercial Disposal Wells, the Applicant:

A) Has an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest in the entity exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

B) Was an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

C) Is a Permit Holder or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

D) If the Director determines that the applicant, or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5% in the applicant, has a history of violating an oil and gas statute, rule, permit condition or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities, which pose a potential danger to the environment and public health and safety. In making the determination, the Director may consider:

i) The danger to the environment and public health and safety if the applicant's proposed activity is not conducted in a competent and responsible manner; and

ii) The degree to which past and present oil and gas related activities directly bear upon the reliability, competence, and responsibility of the applicant.

E) If a permit is not issued in accordance with subparagraph o) 2) above, the Applicant may request to have the permit application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

r) The Commission retains jurisdiction to determine zones suitable for injection based on the porosity, permeability, fluid capacity, structure, geology and overall suitability of the zone as a disposal injection interval with respect to protection of USDWs, oil and gas resources and correlative rights.

s) UIC Well Drilling Permit or Transfer Revocation Procedures

1) The Director may revoke a UIC Well permit or transfer approval if the Permit Holder fails to meet permit conditions as specified in the UIC Well permit or transfer approval, the UIC Well permit or transfer approval was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the UIC Well permit or transfer revocation in writing. Following the revocation notice the Permit Holder is required to plug the UIC Well. The Permit holder shall have thirty (30) days from the date of the UIC Well permit or transfer revocation to appeal the Director's Decision to revoke the UIC Well permit or transfer approval in accordance with General Rule A-2, A-3 and other applicable hearing procedures. Operations may not commence or continue during the appeal process. A revocation of a UIC Well permit or transfer approval for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

t) UIC Well Transfer Procedures

1) Definitions

A) "Current Permit Holder" means the individual or entity required to hold the permit or to whom the permit was issued and who is the owner of the right to operate said UIC Well(s), possesses the full rights and responsibilities for operating the UIC Well(s) in accordance with applicable Arkansas law and has the current obligation to plug said UIC Well(s), who is the assignor, transferor or seller (whether voluntary or involuntary) of the UIC Well(s).

B) "New Permit Holder" means the individual or entity acquiring the UIC Well(s) and the right to operate said UIC Well(s), who obtains the full rights and responsibilities for operating the UIC Well(s) in accordance with applicable Arkansas law and/or rule or order of the Commission, who will obtain the obligation to plug said UIC Well(s), and who as owner or operator in accordance with applicable Arkansas law and/or rule or order of the Commission is required to hold the permit.

C) "Transfer" means any assignment, devise, release, transfer, takeover, buyout, merger, sale, conveyance, or other transfer of any kind, whether voluntarily or involuntarily.

2) The provisions of this subparagraph apply to all transfers of the interest of the individual or entity required to hold and to whom the UIC Well transfer approval is issued (Permit Holder), including but not limited to:

A) a change of ownership of the right to drill and/or operate said UIC Well(s), along with the full rights and responsibilities for operating the UIC Well(s) and the obligation to ultimately plug said UIC Well(s); or

B) a change in the designation of the owner or operator under an operating or other similar agreement; or

C) a change pursuant to the action of the owners of separate interests who designate an owner to be Permit Holder; or

D) a change required by the appointment, by a court of competent jurisdiction, of a trustee or a receiver to exercise custody and control over the UIC Well(s), including the right to drill and/or operate said well(s) along with the full right and responsibilities for operating the UIC Well(s).

3) The provisions of this subparagraph shall not apply to the transfer of working interests not affecting the rights or responsibilities of the Permit Holder.

4) The provisions of this subparagraph shall not apply to transfers of UIC Well(s) abandoned or orphaned in accordance General Rule G-1 or G-2. Transfers of UIC Wells deemed abandoned or orphaned are subject to the transfer provisions in General Rule G-3.

5) Notification of a transfer shall be given to the Director, or his designee, by the Current Permit Holder, on a form prescribed by the Director, of the transfer of any UIC Well or any UIC Well required to be permitted within thirty (30) days after the effective date of the transfer.

6) A separate form shall be completed for each lease, UIC Well, or other unit transferred.

7) The notification shall be signed by the Current Permit Holder and the New Permit Holder, or by authorized representatives specified on the Organizational Report filed in accordance with General Rule B-13, except as follows:

A) In lieu of the signature of the Current Permit Holder, the New Permit Holder may submit a court order or other legal document evidencing ownership of the lease or unit to be transferred in the event that the Current Permit Holder cannot be located or refuses to sign the notification of transfer form.

B) In lieu of the signature of the New Permit Holder, the Current Permit Holder may submit documentation evidencing transfer of the ownership of the UIC Well, lease, or unit in the event the New Permit Holder refuses to sign the notification of transfer form.

8) A New Permit Holder may operate UIC Wells covered by the UIC Well transfer request, until such time as the transfer request has been approved or denied by the Director or his designee, provided the request was submitted within thirty (30) days of the actual transfer of the UIC Well. However, UIC Wells may not be operated by the New Permit Holder,

until a UIC Well transfer request is approved, if the request was received by the Director, or his designee, more than thirty (30) days after the actual transfer of the UIC Well.

9) A New Permit Holder that acquires the right to operate a UIC Well(s) pursuant to a transfer shall apply for and must receive transfer approval from the Director, or his designee, prior to operating the UIC Well(s) beyond the timeframe specified in subparagraph t)(8) above.

10) Prior to the Director, or his designee, approving the transfer request, the New Permit Holder shall provide the required financial assurance, if applicable, in accordance with General Rule B-2, and file the required organizational report, if applicable, in accordance with General Rule B-13.

11) A transfer to a New Permit Holder may be denied by the Director, or his designee, if the New Permit Holder meets any of the conditions specified in subparagraph q) above.

12) The New Permit Holder shall be responsible for all regulatory requirements relative to all UIC Wells and all other surface production facilities in existence at the time of the transfer related to the UIC Wells. The New Permit Holder shall not be responsible for regulatory requirements relative to spills of crude oil or other production fluids which occurred prior to the date of the transfer, unless the New Permit Holder has otherwise agreed with the Current Permit Holder.

13) If any UIC Well, or any lease or other unit associated with the UIC Well, is in violation at the time of the transfer request to the New Permit Holder, the transfer request shall be denied pending abatement of all violations by the Current Permit Holder. However, if the New Permit Holder, after being notified of the violation(s), agrees in writing to the transfer approval including conditions to abate all violations, the transfer may be approved by the Director, or his designee. Failure to abate the violations within the time period specified by the Director or his designee may result in revocation of the transfer approval in accordance with subparagraph s) above, and/or other applicable enforcement actions in accordance with General Rule A-5.

14) The Current Permit Holder is not responsible for any regulatory violation caused by the actions of the New Permit Holder during the permit transfer process, after notice is given to the Director, or his designee, by the Current Permit Holder of the pending transfer if the transfer is approved. However, if the transfer is denied by the Director or his designee, the Current Permit Holder assumes all responsibility for the violations caused by the New Permit Holder. Nothing in this subsection shall affect the contractual rights and obligations between the person or entity transferring the UIC Well(s) and the person or entity acquiring the UIC Well(s).

15) The transfer approval pursuant to this subparagraph shall not affect the rights of the Commission, or any obligation or duty of the Current Permit Holder arising under any applicable Arkansas laws, or rules or orders of the Commission. Any cause of action accruing or any action or proceeding which has commenced, whether administrative, civil or criminal, may be instituted or continued without regard to the transfer approval.

16) The Director shall notify the Current and New Permit Holder of the transfer approval or denial in writing. Following the approval or denial of the transfer approval request, the Current or New Permit holder shall have thirty (30) days from the date of the approval or denial to appeal the Director's Decision in accordance with General Rule A-2, A-3 and other applicable hearing procedures. A transfer request approval or denial, for which an

appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the approval or denial.

u) Miscellaneous Provisions and Requirements for Class II Disposal or Class II Commercial Disposal Wells Within General Rule B-43 Section c) lands.

1) Definitions:

a. "Regional Fault" means the identified fault zones named by the Arkansas Geological Survey as the Clinton, Center Ridge, Heber Springs, Enders and Morrilton Fault zones; and which are part of a general east-west turning north-east (approximately N55ºE to N75ºE) trending, down thrown to the south, fault system generally occurring below the Fayetteville Shale Formation displacing the Lower Mississippian through Precambrian strata and truncating upward at the unconformity between the Mississippian and Pennsylvanian age strata; and which are identified on the Arkansas Geological Survey map attached hereto as Exhibit 1 to this Rule; and as updated for purposes of this Rule following notice and a hearing in accordance with General Rule A-2.

b. "Moratorium Zone Deep Faults" means deeper faults associated with the Guy-Greenbrier Earthquake Swarm; and which are part of a general northeast-southwest (approximately N30ºE) trending deeper fault system displacing the Lower Ordovician through Precambrian strata occurring in the general B-43 Section c) lands area.

2) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well may be granted for any Class II or Class II Commercial Disposal wells in any formation within the following area ("Moratorium Zone") located in Cleburne, Conway, Faulkner, Van Buren, and White Counties:

Sections	Township	Range
ALL	4N	13W
ALL	5N	12W
ALL	5N	13W
ALL	5N	14W
ALL	6N	12W
ALL	6N	13W
ALL	7N	11W
ALL	7N	12W
ALL	7N	13W
ALL	8N	11W
ALL	8N	12W
ALL	8N	13W
ALL	9N	10W
ALL	9N	11W
ALL	9N	12W
ALL	10N	10W
ALL	10N	11W
ALL	11N	10W
ALL	11N	11W
1-12, 14-23, 27-33	4N	12W
1-30, 35-36	4N	14W
1-2, 10-15, 23-25	4N	15W
4-9, 17-20, 30-31	5N	11W
25, 35-36	5N	15W
6	6N	10W
1-23, 26-34	6N	11W
1-4, 9-36	6N	14W
24-25, 36	6N	15W
3-9, 16-20, 29-31	7N	10W
1, 11-14, 22-27, 34-36	7N	14W
6-7	8N	9W
1-24, 26-35	8N	10W
25, 36	8N	14W
3-10, 15-21, 29-32	9N	9W
1-5, 7-36	9N	13W
1-23, 27-34	10N	9W
1-3, 9-17, 19-36	10N	12W
25, 33, 34, 36	10N	13W
17-22, 27-35	11N	9W
13, 23-27, 34-36	11N	12W

3) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill or re-enter, a new Class II Disposal or Class II Commercial Disposal Well may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

4) Unless otherwise approved by the Commission after notice and a hearing, no permit to deepen or re-complete any existing Class II Disposal or Class II Commercial Disposal Well in a zone stratigraphically below the Fayetteville Shale formation, may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

5) Unless otherwise approved by the Commission after notice and a hearing, the following provisions shall apply to any permit to drill, deepen, or operate a new Class II Disposal or Class II Commercial Disposal Well proposed to be located within in any remaining B-43 Section c) lands:

   a) No Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation shall be located within five (5) miles of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation.

   b) No Class II Disposal or Class II Commercial Disposal well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation shall be located within one-half (1/2) mile of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation.

6) The Applicant shall provide technical information to the Director in support of the application. The technical justification shall include information related to the location of any Moratorium Zone Deep Fault within five (5) miles or Regional Fault within two miles (2) of the proposed location of the Class II Disposal or Class II Commercial Disposal Well, with special emphasis on identifying any deep faults occurring below the Fayetteville Shale formation which extend to the basement rock.

7) Flow meters, or other measuring devices approved by the Director, shall be installed on all Class II Disposal and Class II Commercial Disposal Wells and Permit Holders shall submit accurate injection volume and pressure information, on no less than a daily basis, on a form prescribed by the Director.

(Source: new rule July 17, 2009; amended November 26, 2009; amended July 30, 2010; amended July 29, 2011; amended February 17, 2012; amended June 16, 2019)

RULE H-2: WELL CONSTRUCTION, OPERATING AND REPORTING REQUIREMENTS FOR CLASS II DISPOSAL WELLS

a) No Class II Disposal or EOR Well, as defined in General Rule H-1 a) 1) (hereinafter referred to as "Class II Well" for purposes of this Rule), for which a permit has been issued in accordance with General Rule H-1, shall be operated until well internal mechanical integrity has been established in accordance with sub-paragraph o) below, and an authority for initial commencement of injection operations is issued by the Director.

b) The permit holder shall provide notice to the Commission Regional Office where the Class II Well is located, prior to performing any well servicing activity, cementing, or any wireline logging activities, so as to allow commission staff to be present to observe the activity. Any well servicing which requires the resetting of the packer shall require an internal mechanical integrity test be run in accordance with subparagraph o) below, prior to re-commencement of injection.

c) All well records for newly drilled Class II Wells shall be submitted in accordance General Rule B-5. Completion or recompletion reports and wireline logs for all subsequent well servicing, cementing or wireline logging activity performed on the well shall be filed no later than fifteen (15) days after completion of these activities.

d) Following issuance of the permit to drill and or operate a Class II Well, an annual fee of $100 per well shall be due each July 1st for the life of the well until the well is plugged.

e) Surface and production casing requirements.

1) Class II Wells shall be cased and cemented, in such manner that damage will not be caused to any USDW, as defined in General Rule H-1 a) 5) (hereinafter referred to as "USDW"), or oil and gas resources.

2) For newly drilled Class II Wells

A) Set and cement surface casing 250 feet below the base of the lowermost USDW, and cement production casing to at least 250 feet above the proposed disposal zone; or

B) Set and cement surface casing fifty (50) feet below the base of the lowermost formation utilized for a public water system (see 40 CFR) in the area of the Class II Well, with a minimum of five hundred (500) feet of surface casing required, and cement production casing back to the surface.

3) For existing wells converted to Class II Wells

A) Unless otherwise approved by the Director, production casing in the existing well is required to be cemented to at least 250 feet above the proposed disposal zone. A cement bond (CBL), gamma ray (GR) and density log (VDL) shall be required to verify the presence of the required casing cement. The CBL should indicate at a minimum an 80% bond index over the 250 foot cemented interval.

B) If a casing liner is required to provide well bore integrity above the required production cementing requirements in subparagraph e) 3) A) above, the liner must be set, at a minimum, below the cemented portion of the production casing and cemented back to surface.

f) Tubing and packer requirements.

1) All injection shall be through tubing and packer. The packer shall be placed no higher than 100 feet above the uppermost perforations or the casing seat in an open hole completion, provided the packer is within the cemented portion of the production casing, provided the packer is no less than 500 feet below the base of the USDW.

2) If the tubing and packer cannot be set or utilized in accordance with subsection f) 1) above, due to existing well construction conditions, the Permit Holder may request the Director to authorize an alternative packer setting depth or well construction. In determining an alternative packer setting depth or alternative well construction, the Director shall take into consideration the current construction of the well, the depth of the USDWs and the nature of the obstruction. If an alternative packer setting depth or well construction is authorized, the Director may require additional or more frequent internal mechanical integrity tests be performed on the well, or may require additional remedial or corrective work to assure that injection does not endanger USDWs.

3) The Permit Holder shall contact the Regional Office in which the well is located at least 24 hours prior to the initial setting or any resetting of the packer in a Class II Disposal Wells to enable an inspector to be present when the packer is set.

g) The wellhead shall be maintained in a leak-free condition, and must have a working pressure guage in excess of the maximum discharge pressure of the pump. The wellhead shall be configured to include a one half inch female fitting, with shut-off valve, to allow monitoring of the annulus between the production casing and the injection tubing and a one half inch female fitting, with shut-off valve, installed on the tubing to measure the injection pressure.

h) The injection pressure shall not exceed the maximum injection pressure established in accordance with General Rule H-1 h) 8).

i) No change shall be made in the permitted injection zones unless the new zone is permitted in accordance with General Rule H-1.

j) Injection fluids shall be confined to the permitted injection zones. If the Director has reason to believe, based upon well records or field observations, that injection fluids are migrating into zones not permitted for injection or into USDWs or to the surface or is causing fluid migration into the USDWs, due to the operation of any Class II Well or resulting from a failure of internal or external mechanical integrity of the well, the Permit Holder shall be required to shut-in the well until all necessary corrective work, which may include plugging of the well, is completed.

k) Internal mechanical integrity shall be maintained in accordance with subparagraph o) below.

l) Only Class II Fluids, as defined in General Rule H-1 a) 3), and/or fresh water can be injected into a Class II Well.

m) Each well shall have a legible sign placed near the well showing the Permit Holder and the well name and number and permit number and section, township and range as shown on the permit in the Commission records.

n) The Permit Holder of each Class II Well shall file a Quarterly Well Status Report on forms prescribed by the Director. The report shall be filed within thirty (30) days after the end of each quarter of a calendar year commencing on January 1 of each year. The report shall include at a minimum:

1) Name and permit number of the well;

2) Names of all injection intervals;

3) Maximum daily injection rates and pressures; and

4) Monthly volumes of fluid injected.

o) Establishment of Internal Mechanical Integrity.

1) Internal mechanical integrity must be maintained at all times. If internal mechanical integrity is lost, the Permit Holder shall shut-in the well immediately and notify the Regional Office where the well is located, of loss of internal mechanical integrity. The well shall remain shut-in until the necessary remedial action necessary to restore internal mechanical integrity is completed and a new internal mechanical integrity test run and successfully passed.

2) An internal mechanical integrity test shall be performed:

A) Prior to initial injection into a newly permitted Class II Well;

B) Prior to initial injection into a Class II Well after a change to a newly permitted injection zone;

C) Prior to resuming injection into any Class II Well after any workover of the well involving the resetting or movement of a packer;

D) Whenever the Director has reason to believe, based upon well records or field observation, that the Class II Wells may be leaking or improperly constructed; and

E) At least once every five (5) years measured from the date of the last successful test.

3) Internal mechanical integrity test

A) The following tests shall be performed on Class II Wells to establish the internal mechanical integrity of the tubing, casing and packer of the well. The Permit Holder shall contact the Regional Office in which the well is located at least 48 hours prior to conducting the test to enable an inspector to be present when the test is done.

i) Pressure Test

The casing-tubing annulus above the packer shall be tested under the supervision of a Commission representative at a minimum pressure differential between the tubing and the annulus of fifty (50) psig for a period of thirty (30) minutes. The casing-tubing annulus starting test pressure shall not be less than three hundred (300) psig and may vary no more than ten (10) percent of the starting test pressure during the test. The pressure at which the test is to be performed shall be fifty (50) psig over the permitted injection pressure, with a maximum of one thousand (1000) psig.

ii) Radioactive Tracer Survey Test

For those wells in which alternative well construction has been approved by the Director in accordance with subparagraph f) 2) above, a radioactive tracer survey may be run in the well at a frequency to be determined by the Director to evidence mechanical integrity of the well by demonstrating that the injected fluid is being injected into the approved disposal zone.

B) Any Class II Well which fails an internal mechanical integrity test, or on which an internal mechanical integrity test has not been performed when required, shall be shut in until the well is successfully tested or remedial work is commenced and completed or the well is plugged. The necessary work shall be completed and an internal mechanical integrity test successfully completed within ninety (90) days. The Director may approve up to an additional ninety (90) days, with any greater length of time to be established by the Commission upon application by the operator.

p) If the Director has reason to believe, based upon well records or field observation, that any Class II Well is causing fluid migration into the USDWs resulting from a failure of internal or external mechanical integrity, the Permit Holder shall shut in the well until any necessary corrective work is commenced and completed and internal and external mechanical integrity is established.

q) Class II Wells no longer in service for periods greater than 24 months shall be plugged or temporarily abandoned in accordance with General Rule B-7.

(Source: new rule July 17, 2009; amended October 24, 2009; amended June 16, 2019)

RULE H-3: WELL CONSTRUCTION, OPERATING AND REPORTING REQUIREMENTS FOR CLASS II COMMERCIAL DISPOSAL WELLS

a) No Class II Commercial Disposal Well, as defined in General Rule H-1 a) 2) (hereinafter referred to as "Class II Commercial Disposal Well") for which a permit has been issued in accordance with General Rule H-1, shall be operated until well internal mechanical integrity has been established in accordance with sub-paragraph o) below, and an authority for initial commencement of injection operations is issued by the Director.

b) Notice shall be provided to the Commission Regional Office where the Class II Commercial Disposal Well is located, prior to performing any well servicing activity, cementing, or any wireline logging activities, so as to allow Commission staff to be present to observe the activity. Any well servicing which requires the resetting of the packer shall required an internal mechanical integrity test be run in accordance with subparagraph o) below, prior to re-commencement of injection.

c) All well records for newly drilled Class II Commercial Disposal Wells shall be submitted in accordance General Rule B-5. Completion or recompletion reports and wireline logs for all subsequent well servicing, cementing or wireline logging activity performed on the well shall be filed no later than fifteen (15) days after completion of these activities.

d) Following issuance of the permit to Drill and or Operate a Class II Commercial Disposal Well, an annual fee of $100 per well shall be due each July 1st for the life of the well until the well is plugged.

e) Surface and production casing requirements.

1) Class II Commercial Disposal Wells shall be cased and cemented, in such manner that damage will not be caused to oil and gas resources or any USDW, as defined in General Rule H-1 a) 5) (hereinafter referred to as "USDW").

2) Existing wells shall be prohibited for re-completion as a Class II Commercial Disposal Well unless the well had been constructed at the time of original completion in accordance with subparagraph e) 3) below.

3) Newly drilled Class II Commercial Disposal Wells:

A) Set and cement surface casing 250 feet below the base of the lowermost USDW, and cement production casing to at least 500 feet above the proposed disposal zone; or

B) Set and cement surface casing fifty (50) feet below the base of the lowermost formation utilized for a public water system (see 40 CFR) in the area of the Class II Commercial Disposal Well, with a minimum of five hundred (500) feet of surface casing required, and cement production casing back to the surface.

C) A cement bond (CBL), gamma ray (GR) and density log (VDL) shall be required to verify the presence of the required casing cement. The CBL should indicate at a minimum an 80% bond index over the 500 foot cemented interval.

f) Tubing and packer requirements.

1) All injection shall be through tubing and packer. The packer shall be placed no higher than 100 feet above the uppermost perforations or the casing seat in an open hole completion, provided the packer is within the cemented portion of the production casing, provided the packer is no less than 750 feet below the base of the lowermost USDW.

2) The Permit Holder shall contact the District Office in which the well is located at least 24 hours prior to the initial setting or any resetting of the packer in a Class II Commercial Disposal Well to enable an inspector to be present when the packer is set.

g) The wellhead shall be maintained in a leak-free condition, and must have a working pressure gauge in excess of the maximum discharge pressure of the pump. The wellhead shall be configured to include a one half inch female fitting, with shut-off valve, to allow monitoring of the annulus between the production casing and the injection tubing and a one half inch female fitting, with shut-off valve, installed on the tubing to measure the injection pressure.

h) The injection pressure shall not exceed the maximum injection pressure established in accordance with General Rule H-1 h) 8).

i) No change shall be made in the permitted injection zones unless the new zone is permitted in accordance with General Rule H-1.

j) Injection fluids shall be confined to the permitted injection zones. If the Director has reason to believe, based upon well records or field observations, that injection fluids are migrating into zones not permitted for injection or into USDWs, or to the surface, or is causing fluid migration into the USDWs, due to the operation of any Class II Commercial Disposal Well or resulting from a failure of internal or external mechanical integrity of the well, the Permit Holder shall be required to shut-in the well until all necessary corrective work, which may include plugging of the well, is completed.

k) Internal mechanical integrity shall be maintained in accordance with subparagraph o) below.

l) Only Class II Fluids, as defined in General Rule H-1 a) 3), and/or fresh water can be injected into a Class II Commercial Disposal Well.

m) Each well shall have a legible sign placed near the well showing the Permit Holder and the well name and number and permit number and section, township and range as shown on the permit in the Commission records and an emergency telephone number.

n) The Permit Holder of each Class II Commercial Disposal Well shall file a Monthly Well Status Report on forms prescribed by the Director. The report shall be filed within thirty (30) days after the end of each month of a calendar year commencing on January 1 of each year. The report shall include at a minimum:

1) Name and permit number of the well;

2) Names of all injection intervals;

3) Maximum daily injection rates and pressures; and

4) Monthly volumes of fluid injected.

5) In addition, each Class II Commercial Disposal Well facility must keep an accurate log of each shipment of fluids to be disposed. This log shall include the generator (operator) of

the fluid, well name, number and location or permit number of the well, amount of fluid and the date the shipment was received. A copy of this log must accompany the above Monthly Well Status Report.

o) Establishment of Internal Mechanical Integrity.

1) Internal mechanical integrity must be maintained at all times. If internal mechanical integrity is lost, the Permit Holder shall shut-in the well immediately and notify the Regional Office where the well is located, of loss of internal mechanical integrity. The well shall remain shut-in until the necessary remedial action necessary to restore internal mechanical integrity is completed and a new internal mechanical integrity test run and successfully passed.

2) An internal mechanical integrity test shall be performed:

A) Prior to initial injection into a newly permitted Class II Commercial Disposal Well;

B) Prior to initial injection into a Class II Commercial Disposal Well after a change to a newly permitted injection zone;

C) Prior to resuming injection into any Class II Commercial Disposal Well after any workover of the well involving the resetting or movement of a packer;

D) Whenever the Director has reason to believe, based upon well records or field observation, that the Class II Commercial Disposal Well may be leaking or improperly constructed; and

E) At least once every year measured from the date of the last successful test.

3) Internal mechanical integrity test

A) The following test shall be performed on Class II Commercial Disposal Wells to establish the internal mechanical integrity of the tubing, casing and packer of the well. The Permit Holder shall contact the Regional Office in which the well is located at least forty-eight (48) hours prior to conducting the test to enable an inspector to be present when the test is done. The casing-tubing annulus above the packer shall be tested under the supervision of a Commission representative at a minimum pressure differential between the tubing and the annulus of fifty (50) psig for a period of thirty (30) minutes and may vary no more than ten (10) percent of the starting test pressure during the test. The pressure at which the mechanical integrity test is to be performed shall be fifty (50) psig over the permitted injection pressure with a maximum of one thousand (1,000) psig. The minimum test pressure shall be three hundred (300) psig.

B) Any Class II Commercial Disposal Well which fails an internal mechanical integrity test, or on which an internal mechanical integrity test has not been performed when required, shall be shut in until the well is successfully tested or remedial work is commenced and completed or the well is plugged. The necessary work shall be completed and an internal mechanical integrity test successfully completed within ninety (90) days. The Director may approve up to an additional ninety (90) days, with any greater length of time to be established by the Commission upon application by the operator.

p) All commercial facilities must have restricted entry to all nonessential traffic. A lockable gate must be maintained and shall be locked during all unmanned hours. Additionally, the Director may require a fence to limit entry to the facility.

q) Permit Holders may be required to take periodic samples of the injection fluid and have those samples analyzed at a certified lab. Samples of the injection fluid may also be taken periodically by a Commission representative. Samples will be checked for compliance with Class II fluids as defined in General Rule H-1.

r) If the Director has reason to believe, based upon well records or field observation, that any Class II Commercial Disposal Well is causing fluid migration into the USDWs resulting from a failure of internal or external mechanical integrity, the Permit Holder shall shut in the well until any necessary corrective work is commenced and completed and internal and external mechanical integrity is established.

s) Class II Commercial Disposal Wells no longer in service for periods greater than 12 months shall be plugged in accordance with General Rule B-7.

(Source: new rule July 17, 2009; amended October 24, 2009)