OPERATIONS AND REPORTING
400 SERIES

401. LOCATION OF WELL COMPLETIONS

All Wells drilled for oil or gas will have the following completion setbacks:

a. Well Completions 2,500 Feet or Greater in Depth. A Well completion 2,500 feet or greater below the surface will be located not less than 600 feet from any lease line and not less than 1,200 feet from any other existing or permitted Well completion in the same common source of supply, unless authorized by order of the Commission or an exception under Rule 401.c is obtained.

b. Well Completions Less than 2,500 Feet in Depth. A Well completion less than 2,500 feet below the surface will be located not less than 200 feet from any lease line and not less than 300 feet from any other existing or permitted Well completion in the same common source of supply, except that only one Well completion in each such source of supply will be allowed in each governmental quarter-quarter section unless authorized by order of the Commission or an exception under Rule 401.c is obtained.

c. Exception Locations.

(1) Operators may request in writing from the Director an exception to the Well completion location requirements of this Rule, or any order, because of geologic, environmental, topographic, or archaeological conditions, irregular sections, a Surface Owner request, or for other good cause shown. The Operator will submit the written exception location request and waivers pursuant to Rule 401.c.(2).B, as attachments to the Form 2, Application for Permit to Drill.

(2) The Director will not approve an exception request unless the Operator:

A. Demonstrates in sufficient detail that correlative rights are protected; and

B. Submits with its request one of the following waivers authorizing the encroachment:

i. If the proposed Well completion encroaches upon an unspaced lease, a waiver will be signed by the Owner unless Rule 401.c.(2).B.iii applies.

ii. If the proposed Well completion encroaches upon a unit, a waiver will be signed by all Owners within the unit, unless Rule 401.c.(2).B.iii applies.

iii. If the Operator of the proposed Well is the Owner of an encroached-upon unspaced lease, or of a lease within an encroached-upon unit, a waiver will be signed by the leased mineral interest Owners.

d. Exemptions to Rule 401.

(1) Rule 401 does not apply to authorized secondary or tertiary recovery projects;

(2) Rule 401 does not apply to Wells completed in fractured shale reservoirs in fields discovered prior to 1964; and

(3) In a unit operation approved by federal or state authorities, these Well completion location requirements apply to the exterior or interior (if one exists) boundary of the unit area unless otherwise authorized by Commission order after proper notice to Owners outside the unit area.

e. Wells Located Near a Mine. No Well will be located within 200 feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor will such Well be located within 100 feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed Well will ensure that when drilled it will be at least 15 feet from any mine haulage or airway.

402. GREATER WATTENBERG AREA SPECIAL WELL LOCATION AND UNIT DESIGNATION RULE

a. The Greater Wattenberg Area ("GWA") is defined to include those lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, 6th P.M.

b. As of January 15, 2021, the GWA special Well location, spacing, and unit designation Rule 318A is no longer in effect and future operations and development within the GWA will be subject to all of the Commission's Rules and orders.

c. Wellbore Spacing Units created under Rule 318A prior to January 15, 2021 will remain in effect unless the Form 2 expires without spud.

d. A proposed Oil and Gas Location within the GWA with a valid Form 2A, Oil and Gas Location Assessment may be constructed prior to the expiration of the current Form 2A. If not constructed prior to the expiration of the current Form 2A, the proposed Oil and Gas Location will be resubmitted as part of an Oil and Gas Development Plan.

e. A proposed Well within the GWA with a valid Form 2 may be drilled prior to the expiration of the current Form 2. If the Well is not drilled prior to the expiration of the current Form 2, the proposed Well will be resubmitted as part of an Oil and Gas Development Plan.

403. YUMA/PHILLIPS COUNTY SPECIAL WELL LOCATION RULE

a. This Special Well Location Rule ("Yuma WLR") governs Wells drilled to and completed in the Niobrara Formation for the following lands:

<u>Township 1 North</u> Range 44 West: Sections 7, 18, 19, 30 through 33 Range 45 West: Sections 7 through 36 Range 46 West: Sections 4 through 9 Range 47 West: All Range 48 West: All

<u>Township 2 North</u> Range 46 West: All Range 47 West: All Range 48 West: All

<u>Township 3 North</u> Range 45 West: Sections 1 through 18 Range 46 West: All Range 47 West: All Range 48 West: All

<u>Township 4 North</u> Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

<u>Township 5 North</u> Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

<u>Township 6 North</u> Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

<u>Township 7 North</u> Range 45 West: All Range 46 West: All Range 47 West: All

Township 8 North Range 45 West: All Range 46 West: All Range 47 West: All

Township 9 North Range 45 West: Sections 19 through 36 Range 46 West: Sections 19 through 36 Range 47 West: Sections 19 through 36

Township 1 South Range 44 West: Sections 3 through 10, 16 through 21, 27 through 34 Range 45 West: Sections 3 through 5 Range 46 West: Sections 4 through 9, 16 through 36 Range 47 West: All Range 48 West: All

Township 2 South Range 44 West: Sections 3 through 6 Range 45 West: Section 7: W½, Section 18: W½, Section 19: All Range 46 West: Sections 1 through 24 Range 47 West: All Range 48 West: All

Township 3 South Range 48 West: All

Township 4 South Range 48 West: All

b. Within the Yuma WLR area, Operators may conduct drilling operations to the Niobrara Formation as follows:

(1) 4 Niobrara Formation Wells may be drilled in any quarter section;

(2) No more than 1 Well may be located in any quarter quarter section;

(3) No minimum distance will be required between Wells producing from the Niobrara Formation in any quarter section; and

(4) Wells will be located at least 300 feet from the boundary of said quarter section, and Wells located outside any drilling units established by the Commission in the Yuma WLR area prior to July 30, 2006 will, in addition, be located at least 300 feet from any lease line. Further, Wells will be located not less than 900 feet from any producible Well drilled to the Niobrara Formation prior to July 30, 2006, located in a contiguous or cornering quarter section unless an exception is approved by the Director.

c. Any Well drilled to the Niobrara Formation in the Yuma WLR area prior to July 30, 2006, but not located as described in Rule 403.b will be treated as properly located for purposes of this Rule 403.

d. This Yuma WLR does not alter the size or configuration of any drilling units established by the Commission in the Yuma WLR area prior to July 30, 2006.

e. This Yuma WLR will not serve to bar the granting of relief to Owners who file an application alleging abuse of their correlative rights to the extent that such Owners can demonstrate that their opportunity to produce from the Niobrara Formation at locations herein authorized does not provide an equal opportunity to obtain their just and equitable share of oil and gas from such formation.

f. Well exception locations to this Yuma WLR will be subject to the provisions of Rule 401.c.

g. This Yuma WLR is a Well location rule and supersedes existing Commission orders in effect at the time of its adoption only to the extent that the existing orders relate to permissible Well locations and the number of Wells that may be drilled in a quarter section. Commission orders in effect when this Rule is adopted nonetheless apply with respect to the size of drilling units already established by the Commission in the Yuma WLR area. This Yuma WLR is not intended to establish Well spacing. Accordingly, when an area subject to Rule 403 is otherwise unspaced, it does not act to space the area but instead provides the permissible locations for any new Niobrara Formation Wells. Similarly, Rule 403 does not affect production allocation for existing or future Wells. An Operator may allocate production pursuant to the applicable lease, contract terms or established Drilling and Spacing Units recognizing the Owner's right to apply to the Commission to resolve any outstanding correlative rights issues.

404. FORM 4, SUNDRY NOTICES

a. The Form 4, Sundry Notice is a multipurpose form which will be used by an Operator to request approval from or provide notice to the Director pursuant to the Commission's Rules or when no other specific form exists.

b. An Operator will comply with Rule 301.c for any Form 4 submitted to propose a change to an approved Oil and Gas Development Plan.

c. An Operator will comply with Rule 304.a for any Form 4 submitted to propose a change to an approved Form 2A.

d. If an Operator submits a Form 4 proposing a change to a previously approved noise, light, odor, or dust plan pursuant to Rules 423.a, 424.a, 426.a, or 427.a, the Director may approve the proposed change only if it provides equally protective or more protective standards to avoid, minimize, or mitigate adverse impacts from noise, light, odor, or dust.

405. FORM 42, FIELD OPERATIONS NOTICE

Operators will submit a Form 42, Field Operations Notice, as designated below and pursuant to a condition of approval on any Form 2; Form 2A; Form 4; Form 6, Well Abandonment Report; or any other approved form. No Form 42 may be submitted more than 2 weeks prior to the scheduled activity, unless a longer timeframe is specified by another Commission Rule. Each Form 42 that notifies the Commission of a forthcoming activity will describe the estimated duration (which may be expressed as a range) for the proposed activity if it is anticipated to last for longer than one day.

a. **Notice of Intent to Conduct Seismic Operations.** Operators will provide the Commission written notice 2 business days in advance of the commencement of Seismic Operations. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Intent to Conduct Seismic Operations. The Commission will provide prompt electronic notice of such intention to the Relevant Local Government.

b. **Notice of Construction or Major Change.** Operators will provide the Commission written notice 2 business days in advance of commencing construction or a major change at any Oil and Gas Location or Oil and Gas Facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Construction or Major Change. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and CPW.

c. **Notice of Pit Liner Installation.** Operators will provide the Commission written notice 2 business days in advance of a Pit liner installation at any facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Pit Liner Installation.

d. **Notice of Completion of Form 2/2A Permit Conditions.** If required by a condition of approval, Operators will provide the Commission written notice of completion of Form 2 or 2A permit conditions at any Well, Oil and Gas Location, or Oil and Gas Facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Completion of

Form 2/2A Permit Conditions. The Commission will provide prompt electronic notice of such completion to CPW for any completions of Form 2A permit conditions for Oil and Gas Locations located in High Priority Habitat.

e. Notice of Move-In, Rig-Up.

(1) For operations with a drilling rig, Operators will provide the Commission written notice 2 business days in advance of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(2) For planned operations with a work-over rig, Operators will provide the Commission written notice 2 business days in advance of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(3) For unplanned operations with a work-over rig, Operators will provide the Commission written notice within 1 business day after commencement of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(4) For any operation identified in Rules 405.e.(1)–(3), the Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and the Division of Water Resources.

f. Notice of Spud. Operator will provide the Commission written notice 2 business days in advance of spudding the surface hole on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Spud. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government.

g. Notice to Run and Cement Casing. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of running and cementing casing on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice to Run and Cement Casing.

h. Notice of Blow Out Preventer Test. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of conducting a blow out preventer test at a Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Blow Out Preventer Test.

i. Notice of Significant Lost Circulation. Within 24 hours of significant lost circulation at any Well, Operators will provide the Commission written notice of the event. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Significant Lost Circulation.

j. Notice of Formation Integrity Test. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of conducting a formation integrity test on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Formation Integrity Test.

k. Notice of Intent to Conduct Hydraulic Fracturing Treatment. Operators will provide the Commission written notice 48 hours in advance of conducting a Hydraulic Fracturing Treatment at any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Hydraulic Fracturing Treatment. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government, the Air Pollution Control Division, and the Division of Water Resources.

l. Notice of Plugging Operations. Operators will give at least 48 hours advance written notice to the Commission prior to mobilizing for plugging any Well. Such notice will be provided on a Form 42, Field Operations Notice – Plugging Operations. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government.

m. Notice of High Bradenhead Pressure During Stimulation. Operators will give written notice to the Commission of high Bradenhead pressure during Stimulation at any Well within 24 hours of measuring the high pressure. Such notice will be provided on a Form 42, Field Operations Notice – Notice of High Bradenhead Pressure During Stimulation.

n. Notice of Mechanical Integrity Test. Operators will provide the Commission written notice 10 days in advance of conducting a mechanical integrity test on a Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Mechanical Integrity Test.

o. Notice of Remedial Cementing Operations. Operators will provide the Commission written notice 48 hours in advance of the commencement of remedial cementing operations. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Remedial Cementing Operations.

p. Notice of Return to Service. Operators will provide the Director with at least 48 hours advance written notice as required by Rules 1104.A.(2).b and 417. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Return to Service.

q. Notice of H_2S on an Oil and Gas Location. Within 48 hours after receipt of a laboratory gas stream analysis showing the presence of hydrogen sulfide (“H_2S”) on an Oil and Gas Location, Operators will provide the Commission written notice of the analysis. Such notice will be provided on a Form 42, Field Operations Notice – Notice of H_2S on an Oil and Gas Location. The Commission will provide prompt electronic notice of such analysis to CPW.

r. Abandonment of Flowline. Operators will provide written notice to the Commission before undertaking and after completing abandonment of on-location Flowlines pursuant to Rule 1105. Such notice will be provided on a Form 42, Field Operations Notice – Abandonment of Flowlines. The Commission will provide prompt electronic notice of such intention to the Relevant Local Government.

s. Well Liquids Unloading. Operators will provide the Director with advance written notice before undertaking Well liquids unloading, as required by Rule 903.d.(1).E. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Well Liquids Unloading. The Commission will provide prompt electronic notice of such notice to the Relevant Local Government. The Operator will submit the Form 42 – Notice of Well Liquids Unloading no later than:

(1) 48 hours prior to conducting Well liquids unloading; or

(2) As soon as possible prior to conducting Well liquids unloading if 48 hours notice would require an alternative or extended Well liquids unloading practice that increases emissions.

t. Groundwater Baseline Sampling and Monitoring. Operators will provide immediate notice to the Director on a Form 42, Field Operations Notice – Water Sample Reporting upon receipt of any analytical results that meet any of the conditions described in Rules 615.e.(4).C & D.

406. GENERAL OIL AND GAS LOCATION CONSTRUCTION RULES

a. Operators will construct Oil and Gas Locations in conformance with the approved Form 2A and all applicable and approved Form 4s.

b. Requirement to Provide Construction Notice. An advance notice will be provided to the Director on a Form 42 – Notice of Construction or Major Change no less than 2 business days prior to commencement of operations with heavy equipment for the construction of an Oil and Gas Location. The Form 42 will include an estimated duration for the proposed construction activity, which may be expressed as a range. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and to CPW.

c. Requirement to Post Location Assessment at the Location. A copy of the approved Form 2A, and any Form 4 modifying the approved Form 2A, will be posted in a protected and conspicuous place on location upon commencement of operations with heavy equipment until the conclusion of interim Reclamation.

d. Location Signage. The Operator will, concurrent with the Rule 412 Surface Owner notice, post a sign not less than 2 feet by 2 feet at the intersection of the lease road and the public road providing access to the Oil and Gas Location, with the name of the proposed Well or Oil and Gas Location, the legal location thereof, and the estimated date of commencement of construction. Such sign will be maintained until Well completion operations and construction operations at the Oil and Gas Location are concluded.

e. Conductors.

(1) An Operator will secure conductors and cellars to prevent accidental access by people, livestock, or wildlife when active work on that conductor is not occurring.

(2) If artesian flows are encountered when a conductor is preset, the Operator will isolate the conductor with cement from the base of the conductor to the anticipated bottom of the cellar by the pump and plug or displacement method. The Operator will file a Form 4 – Report of Work Done, Other: Conductor Artesian Flow for the Oil and Gas Location to document the artesian flow and cementing operation.

(3) If the Operator has not drilled the Well for which the conductor was set within 30 days after setting the conductor, or after rig demobilization and move off (whichever is later), the Operator will have 15 days to comply with the following safety standards for maintaining a preset conductor:

A. Weld a plate on the top of the conductor pipe that remains in place until the conductor is opened for drilling;

B. Cover and fence all rat holes, mouse holes, and cellars with materials sufficient to prevent accidental access by people, livestock, or wildlife and;

C. Maintain all fencing and covers.

(4) If the Operator has not drilled the Well within 3 months of setting the conductor on Crop Land locations or within 6 months on rangeland then the Operator will plug the conductor and perform Reclamation as follows:

A. Cut the conductor pipe four feet below ground level;

B. Fill the conductor pipe with material that is clean, inert, and free from contaminants;

C. Seal the conductor pipe with either a cement plug and a screw cap or a cement plug and a welded steel plate, and backfill the hole to ground level;

D. Remove the cellar ring;

E. Within 30 days of the plugging, submit a Form 4 – Report of Work Done, Other: Plugged Conductor for the Oil and Gas Location, to report the plugging of the conductor(s), that includes photo documentation demonstrating compliance with Rules 406.e.(4).A–D, above; and

F. Perform Reclamation pursuant to either Rule 1003 or Rule 1004.

407. FORM 45, LOCATION CONSTRUCTION REPORT

a. An Operator will submit a Form 45, Location Construction Report within 45 days of completion of interim Reclamation for a new or modified Oil and Gas Location.

b. The Form 45 will include the following information:

(1) Geographic Information System ("GIS") polygon data to describe the as-built boundaries of the entire Oil and Gas Location and of the Working Pad Surface;

(2) A surveyed as-built layout drawing of the Oil and Gas Facilities and Production Facilities, and other temporary and permanent equipment on the location;

(3) A proposed anticipated schedule, by month and year, of the operation phases planned for 1 year following the date the Form 45 is submitted; and

(4) A description of all conductors that have been set, including:

A. Well name and Well number, and API number if the Well has an approved Form 2;

B. Latitude and longitude of the conductor. If Global Positioning System ("GPS") technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 216; and

C. Conductor setting depth, pipe description (including diameter and weight/foot, if applicable), cement volume, and cement job summary (if applicable).

408. GENERAL DRILLING RULES

Unless altered, modified, or changed for a particular Field or formation upon hearing before the Commission the following will apply to the drilling or deepening of all Wells:

a. Closed Loop Drilling. Closed loop drilling is required except where only water-based bentonitic drilling Fluids will be used, the wellbore will not penetrate salt-bearing formations, the Pit will not be in contact with shallow Groundwater, and the Pit will not be located within 2,000 feet of any Building Unit, a lined drilling Pit system may be used.

b. Bottom Hole Location. Unless authorized by the provisions of Rule 410, Operators will drill all Wells so that the horizontal distance between the bottom of the hole and the location at the top of the hole will be at all times a practical minimum.

c. Requirement to Post Permit at the Rig. The Operator will post a copy of the approved Form 2 in a conspicuous place on the drilling rig or workover rig.

d. Requirement to Provide Spud Notice. An Operator will provide advance notice to the Director on a Form 42 – Notice of Spud, no less than 2 business days prior to spudding a Well.

e. Drilling Fluid, Casing, and Cement Program to Isolate Hydrocarbon Formations and Groundwater and for Well Control.

(1) The casing and cementing plan for each Well will prevent migration of oil, gas, and water within Potential Flow Zones from one formation to another behind the casing.

(2) The casing and cementing plan will ensure Groundwater penetrated by the wellbore will be isolated from the infiltration of hydrocarbons or water from other formations penetrated by the wellbore. At a minimum, the Director will require that the Operator's casing and cement plan for a Well will isolate Groundwater with fully-cemented surface casing or a combination of fully-cemented surface casing and stage cement for other casing string(s) across the Groundwater and to a depth 50 feet below the Groundwater and to 50 feet above it or to surface, in formations that meet the following standards:

A. Groundwater that has been classified pursuant to 5 C.C.R. § 1002-41 as Domestic Use – Quality, Agricultural Use – Quality, Surface Water Quality Protection, or Potentially Usable Quality; and

B. Groundwater that has not been classified pursuant to 5 C.C.R. § 1002-41, and with total dissolved solids ("TDS") less than 10,000 mg/l.

C. Only the version of Colorado Department of Public Health and Environment, Water Quality Control Commission ("WQCC"), Regulation Number 41, The Basic Standards for Ground Water, 5 C.C.R. § 1002-41, *et seq.* in effect as of January 15, 2021 applies to this Rule 408.e; later versions do not apply. A copy of 5 C.C.R. § 1002-41 is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, 5 C.C.R. § 1002-41 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available at https://www.colorado.gov/pacific/cdphe/water-quality-control-commission-regulations.

(3) **Surface Casing Where Subsurface Conditions Are Unknown.** In areas where pressure and formations are unknown, surface casing will be run for Well control to reach a depth approved by the Director that is a minimum depth of 10% of true vertical depth ("TVD") of the deepest point of the planned Well (or as required by Commission order) and will be of sufficient size to permit the use of an intermediate string or strings of casings. Surface casing will be set in or through an impervious formation and will be cemented by pump and plug or displacement or other approved method with sufficient cement to fill the Annulus to the top of the hole, all pursuant to reasonable requirements of the Director.

(4) **Surface Casing Where Subsurface Conditions Are Known.** For Wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing, sized at the Operator's option, will be set and cemented to the surface by the pump and plug or displacement or other approved method at a depth approved by the Director, and for Well control, to a minimum depth of 10% of TVD of the deepest point of the planned Well (or as required by Commission order).

(5) Alternate Isolation by Stage Cementing.

A. In areas where Groundwater is of such depth as to make it impractical to set the full amount of surface casing necessary to comply fully with the requirement to isolate Groundwater, the Director may approve isolation by stage cementing behind the intermediate and/or production casing so as to accomplish the required result.

B. If either the top or bottom depths, or the concentration of TDS in identified Groundwater are uncertain or unknown based on available sources of pertinent information as described in Rule 308.b.(6):

i. The Operator will collect site-specific data sufficient to ensure compliance with all casing and cementing requirements of this Rule 408.e, and submit that information in its casing and cementing plan or in an amended plan that is approved by the Director before the Operator completes the Well; or

ii. The Operator's casing and cementing plan will provide for extending surface casing or cementing behind intermediate and/or production casing to isolate all Groundwater where TDS concentrations are uncertain or unknown. To isolate Groundwater, where the top or bottom depth of Groundwater is unknown or uncertain the Operator's casing and cementing plan will provide for:

aa. Extending surface casing and cement from the surface to 50 feet below the lowest bottom depth;

bb. Stage cementing behind intermediate and/or production casing to 50 feet above the highest top or 50 feet below the lowest bottom depth; or

cc. Extending primary production cement from the bottom of the casing to 50 feet above the highest top that is not otherwise isolated by surface casing and cement or alternate stage cement and casing string.

C. If Groundwater not identified in the casing and cementing plan is encountered after setting the surface casing with either (a) a TDS concentration less than 10,000 mg/l, or (b) unknown or uncertain TDS concentration, the Operator will isolate the Groundwater by stage cementing the intermediate and/or production casing with a solid cement plug extending from 50 feet below the Groundwater to 50 feet above the Groundwater, with the Director's approval. In such cases the Operator will submit an amended casing and cementing plan reflecting the Groundwater and stage cementing within 20 days.

(6) All hole intervals drilled prior to reaching the base of the surface casing or as required by permit condition will be drilled with air, fresh water, or a fresh water-based bentonitic drilling mud. Any other additives will be reviewed and approved by the Director prior to use.

(7) All casing cemented in a Well will be steel casing.

(8) Prior to placing casing in the hole, the Operator will ensure the casing has been tested to verify integrity. An Operator may:

A. For new pipe only, use the mill test pressure;

B. Hydrostatically pressure test the casing with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the Well; or

C. Use a casing evaluation tool.

(9) Prior written approval from the Director on a Form 4 is required before commencing any of the following operations:

A. Pumping cement down the Bradenhead access to the Annulus between the production casing (or intermediate casing, if present) and surface casing;

B. All routine or planned casing repair operations; or

C. Any other changes to the casing or cement in the wellbore.

(10) In the case of unforeseen casing repairs during Well operations, the Operator will obtain oral approval from the Director, and will immediately submit a Form 4 confirming the repairs and approval.

(11) An Operator will submit a Form 5, Drilling Completion Report, within 30 days of the completion of the operations listed above, pursuant to Rule 414.b.(3).

(12) Prior written approval from the Director on a Form 4 is required before changing the gross interval of perforations in a completed formation, including into a formation designated as a common source of supply. A Form 5A, Completed Interval Report, will be submitted within 30 days of the gross interval change, pursuant to Rule 416.

f. Cementing.

(1) Operators will use the pump and plug method. An Operator will use a top plug to reduce contamination of cement from the displacement of fluid. An Operator will use a bottom plug or other Director-approved isolation technique or equipment to reduce contamination from drilling mud within the casing.

(2) Unless the Director approves otherwise,

A. The diameter of the drilled hole in which surface casing will be set and cemented will be at least 1.5 inches greater than the nominal outside diameter of the casing the Operator will install; and

B. All other casing will be set and cemented with at least 0.84 inches between the nominal outside diameter of the casing being cemented and the previously set casing’s inside nominal diameter.

(3) The Operator will design and place cement in a manner that inhibits channeling of the cement in the annular space outside of the casing being cemented. During placement of cement, the Operator will monitor pump rates to verify the rates remain within design parameters and ensure displacement meets the design. The Operator will monitor the cementing process to ensure proper cement densities are maintained.

(4) When cement is required, the Operator will use a cement slurry that isolates all Groundwater, hydrocarbon, corrosive, Potential Flow, or hydrogen sulfide zones.

(5) The Operator will prepare cement slurry to:

A. The designed density;

B. Minimize free fluid content, to the extent practicable;

C. Ensure cement slurry free water separation will not exceed 3 milliliters per 250 milliliters of cement; and

D. Ensure the cement mix water chemistry is appropriate for the cement slurry design.

(6) The Operator or cement services provider will test a cement mixture at a rate that is the most frequent of every 6 months or when there is a change in operating conditions, cement type, or cement vendor.

A. The test will be on representative samples of the cement and additives.

B. The Operator will make cement test data available to the Director upon request.

g. Casing Centralization.

(1) **Surface casing.** At a minimum, the Operator will centralize casing as follows:

A. Within 120 feet of the of the surface;

B. At the casing shoe;

C. Above and below a stage collar or diverting tool, if run; and

D. Every fourth joint.

E. The Operator may implement an alternative centralization plan for surface casing if approved by the Director.

(2) **Production and Intermediate Casing.** The Operator will provide adequate centralization or other methods to achieve cementing objectives in accordance with the permitted Well design.

h. Wellbore Circulation. Prior to cementing, the Operator will clean and condition the wellbore to control gas flow, foster adequate cement displacement, and ensure a bond between cement, casing, and the wellbore.

i. Surface and Intermediate Casing Cementing.

(1) The Operator will ensure that all surface and intermediate casing cement required under this Rule 405.i achieves a minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours measured at 800 psi confining pressure and 95º Fahrenheit or at the minimum expected downhole temperature.

(2) The Operator will cement all surface casing with a continuous column from the bottom of the casing to the surface.

(3) After thorough circulation of the wellbore as required by Rule 408.h, the Operator will pump cement behind the intermediate casing to at least 500 feet above the top of the shallowest known production horizon and as required in Rule 408. The Operator will allow cement placed behind the surface and intermediate casing to set a minimum of 8 hours or until 300 psi calculated compressive strength is developed, whichever occurs first, prior to commencing drilling operations. If the surface casing cement level falls below the surface or if there is evidence of inadequate cement coverage, the Operator will consult with the Director and, upon request, provide and implement a corrective action plan prior to drilling ahead.

j. Production Casing Cementing.

(1) The Operator will ensure that all cement required under this Rule 408 placed behind production casing achieves a minimum compressive strength of at least 300 psi after 24 hours and of at least 800 psi after 72 hours both measured at 800 psi at either 95° Fahrenheit or at the minimum expected downhole temperature.

(2) After thorough circulation of a wellbore as required by Rule 408.h, the Operator will pump cement behind the production casing to the shallower of: 500 feet above the top of the shallowest uncovered known producing horizon, isolation of specific geologic intervals specified in the permit, or isolation of any other zone as required by Rule 408.e.

k. Surface Casing Pressure Testing.

(1) Prior to drilling out below the surface casing shoe, the Operator will successfully pressure test the surface casing for a minimum 30 minute duration and to a minimum of 1,500 psi or to a pressure that will determine if the casing has adequate mechanical integrity to meet the Well design and construction objectives.

(2) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the Operator will verify the integrity of the surface casing before running the next casing string by using a casing evaluation tool, conducting a mechanical integrity test, or using an equivalent casing evaluation method submitted to and approved by the Director through a Form 4.

l. Intermediate Casing Pressure Testing.

(1) Prior to drilling out below the intermediate casing shoe, the Operator will successfully pressure test the intermediate casing to ensure integrity is adequate to meet Well design and construction objectives. The Operator will perform the pressure test for a minimum 30-minute duration and to a minimum of 1,500 psi unless otherwise approved by the Director.

(2) The Operator will monitor the Well’s Bradenhead pressure during any pressure test conducted pursuant to Rule 408.l.

m. Production Casing and Stimulation String Pressure Testing.

(1) Prior to Stimulation, the Operator will successfully pressure test the production casing or Stimulation string, if used. The Operator will pressure test from the wellhead to a minimum depth of 200 feet above the TVD of the top perforations.

(2) For production casing that will be exposed to Stimulation and the Stimulation string, the Operator will perform the pressure test for a minimum of 30 minutes and to a minimum of 500 psi greater than the maximum surface pressure anticipated to be imposed during the Stimulation.

(3) For Wells that are not Stimulated and production casing that will not be exposed to the Stimulation, the Operator will perform the pressure test for a minimum of 30 minutes and to a minimum of 500 psi greater than the maximum anticipated surface pressure.

(4) The Operator will monitor the Well's Bradenhead pressure during any pressure test conducted pursuant to Rule 408.m.

n. Casing Pressure Test Monitoring and Success Criteria for All Casing Strings.

(1) An Operator has successfully conducted a pressure test when:

A. The surface pressure does not change more than 5% from the initial test pressure;

B. The pressure does not change more than 1% during the last 5 minutes of the test; and

C. The Bradenhead pressure does not change more than 5% during the test when testing the intermediate or production casings.

(2) In the event of an indication that a Well no longer has mechanical integrity, the Operator may not conduct stimulation on any Well on the Oil and Gas Location until the Operator has determined the Well has mechanical integrity. If a Well intervention is necessary, the Operator will obtain verbal approval from the Director for the intervention and authorization to proceed with the Stimulation.

o. Isolation When Drilling Operations Are Suspended Before Running Production Casing. In the event drilling operations are suspended before production casing is run, the Operator will notify the Director immediately and will take adequate and proper precautions to prevent migration of oil, gas, and water between formations in the open hole until drilling resumes or the Well is Plugged and Abandoned.

p. Protection of Productive Strata During Deepening Operations. If a Well is deepened for the purpose of producing oil and gas from a lower stratum, such deepening to and completion in the lower stratum will be conducted in such a manner as to protect all upper productive strata.

q. Requirement to Evaluate Disposal Zones for Hydrocarbon Potential. If a Well is drilled as a disposal Well then the Injection Zone will be evaluated for hydrocarbon potential. The proposed hydrocarbon evaluation method will be submitted in writing and approved by the Director prior to implementation. The productivity results will be submitted to the Director upon completion of the Well.

r. Requirement to Log Well. For all new drilling operations, the Operator will run a minimum of a resistivity Log with gamma-ray or other petrophysical Log(s) approved by the Director that adequately describe the stratigraphy of the wellbore. A cement bond Log, capable of generating a variable density display, will be run on all production casing or, in the case of a production liner, the intermediate casing, when these casing strings are run. The Operator will submit these Logs and all other Logs run with the Form 5. The Operator will run open-hole Logs or equivalent cased-hole Logs at depths that adequately verify the setting depth of surface casing and any Groundwater coverage. These requirements will not apply to unlogged open-hole completion intervals.

s. Remedial Cementing. If cement coverage in any casing string does not satisfy the requirements of Rule 408.e, the Director may apply a condition of approval for Form 2 to require remedial cementing and a cement bond log or other cement evaluation tool before recompletion, reentering, or deepening operations consistent with the provisions for isolating Groundwater and hydrocarbon bearing zones in this Rule 408.

t. Statewide Wellbore Collision Prevention. An Operator will perform an anti-collision evaluation of all active (producing, shut in, or temporarily abandoned) offset wellbores that have the potential of being within 150 feet of a proposed Well prior to drilling operations for the proposed Well. The Operator will give notice to all offset Operators prior to drilling.

u. Statewide Setback for Hydraulic Fracturing Treatment.

(1) No portion of a proposed wellbore that will be treated by hydraulic fracturing may be located within 150 feet of an existing (producing, shut-in, or temporarily abandoned) or permitted interval of an oil and gas wellbore that has been or will be treated by hydraulic fracturing belonging to another Operator without the signed written consent of the Operator of the encroached upon wellbore. The Operator will attach any signed written consents to the Form 2 for the proposed wellbore.

(2) The Operator will measure the distance between the proposed and offset wellbores using the directional survey for drilled wellbores and the deviated drilling plan for permitted wellbores, or as otherwise reflected in the Commission's Well records. The Operator will measure the distance from the perforation or mechanical isolation device.

v. Notice Prior to Hydraulic Fracturing Treatment. At least 90 days prior to the anticipated commencement of Hydraulic Fracturing Treatment, the Operator of the wellbore that will be stimulated by Hydraulic Fracturing Treatment will provide notice of Hydraulic Fracturing Treatment commencement to all Operators of offset Wells that were identified pursuant Rule 308.b.(7).A.

w. Offset Wellheads and Surface Equipment. Prior to Hydraulic Fracturing Treatments, the Operator will ensure offset existing Wells within 1,500 feet of the wellbore to be hydraulically fractured that are producing, shut-in, or temporarily abandoned have surface equipment (wellhead and master valve) rated to a pressure adequate to contain anticipated surface pressures that could occur from the proposed Hydraulic Fracturing Treatment. For offset Wells that do not have adequately rated surface equipment, the Operator may instead use downhole mechanical isolation above perforations in the objective formation to prevent unanticipated migration of pressure.

x. Consent to Offset Well Mitigation. When an offset Well and a proposed Well are under different operatorship, the Operator of the offset Well will not refuse to have the offset Well appropriately mitigated to meet the requirements of the Commission's Rules necessary to ensure protection of and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

y. Communication Prevention. An Operator will take all necessary measures to prevent communication along any known conduits between a wellbore's hydraulic fracturing-treated interval and Groundwater.

z. Surface Equipment Used in Hydraulic Fracturing Treatment. Prior to beginning a Hydraulic Fracturing Treatment, the Operator will rig up and pressure test any surface equipment exposed to Hydraulic Fracturing Treatment pressure. The Operator will test for the proposed Hydraulic Fracturing Treatment design and, at a minimum, to 110% of the maximum anticipated surface Hydraulic Fracturing Treatment pressure. The test will ensure an appropriate safety factor and prevent Fluid losses.

aa. Hydraulic Fracturing Treatment Monitoring. The Operator will monitor and record Hydraulic Fracturing Treatment parameters including but not limited to the following list:

(1) Surface injection pressure (psig);

(2) Slurry rate (bpm);

(3) Proppant concentration (ppg);

(4) Fluid rate (bpm);

(5) Identities, rates, and concentrations of additives used; and

(6) All other annuli pressures or volumes measured at the surface.

409. REPORT OF RESERVOIR PRESSURE TEST. Where the Director believes it is necessary to prevent waste, protect correlative rights, or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, the Director may require subsurface pressure measurements. Whenever such measurements are made, results will be reported on a Form 13, Bottom Hole Pressure, within 20 days after completion of tests, or submitted on any company form approved by the Director containing the same information.

410. DIRECTIONAL DRILLING

a. Deviated Drilling Plan.

(1) If an Operator intends to drill a deviated (directional, highly deviated, or horizontal) wellbore utilizing controlled directional drilling methods, the Operator will prepare a deviated drilling plan that includes sufficient data to describe the location of the wellbore in three dimensions from not greater than 500 feet below the surface of the ground to total depth.

(2) The Operator will file the deviated drilling plan with the Form 2 in a format approved by the Director.

b. Directional Survey for a Deviated Wellbore.

(1) For an intentionally drilled deviated wellbore the Operator will perform a directional survey of the wellbore in a manner to gather sufficient data to describe the location of the wellbore in three dimensions and from not greater than 500 feet below the surface of the ground to total depth.

(2) The directional survey will be included with the Form 5, and in a format approved by the Director.

c. Inclination Survey for a Non-deviated Wellbore.

(1) For a newly drilled non-deviated wellbore or for the re-entry, recompletion or deepening of an existing wellbore, the Operator will perform an inclination survey of the wellbore and file the inclination survey with the Form 5.

(2) The first shot point of such inclination survey will be made at a depth not greater than 500 feet below the surface, and succeeding shot points will be made either at 500-foot intervals or at the nearest drill bit change thereto, but will not exceed 1,000 feet apart. The inclination survey may be made either during the normal course of drilling or after the Well has reached total depth. A directional survey meeting the requirements of Rule 410.b may be filed in lieu of an inclination survey.

(3) In the event a Form 5 is not required for re-entry, recompletion, or deepening of an existing wellbore, the Operator will file the inclination survey with a Form 4.

(4) The survey will be provided in a format approved by the Director.

d. Wellbore Setback Compliance. The Operator will ensure that the wellbore complies with the setback requirements in the Commission's orders or Rules prior to producing the Well.

411. PUBLIC WATER SYSTEM PROTECTION

a. Surface Water Supply Areas.

(1) Definition. A Surface Water Supply Area is the buffer zones listed in Rule 411.a.(1).B surrounding a Classified Water Supply Segment that includes 5 stream miles upstream from a Public Water System surface water intake.

A. Calculating Buffer Zone Distances. Operators will identify buffer zones by measuring from the ordinary high-water mark of a Classified Water Supply Segment to the nearest edge of the Working Pad Surface.

B. Buffer Zones.

i. The internal buffer zone is located between 0 and 1,000 feet hydraulically upgradient from a Classified Water Supply Segment.

ii. The intermediate buffer zone is located between 1,001 and 1,500 feet hydraulically upgradient from a Classified Water Supply Segment.

iii. The external buffer zone is located between 1,501 and 2,640 feet hydraulically upgradient from a Classified Water Supply Segment.

C. The buffer zones identified by Rule 411.a.(1).B. may be modified by the Commission as a component of reviewing a proposed Oil and Gas Development Plan pursuant to Rule 307 or a hearing pursuant to Rule 503.a to include additional tributaries, including ephemeral streams, if the Director, Public Water System, or CDPHE demonstrate that modification is necessary to protect the Public Water System surface water intake from risks of spills or releases. In making such a determination, the Commission will consider whether Best Management Practices the Operator proposes to employ will provide sufficient protections to tributaries such that modifying the buffer zones is not necessary.

(2) Protections. Operators will comply with the standards established in Rules 411.a.(2).A–C below for the buffer zone in which the Working Pad Surface is proposed or located, and with all standards for zones farther from the Classified Water Supply Segment.

A. Internal Buffer Zone.

i. After January 15, 2021, Operators will not conduct any new surface disturbance within the internal buffer zone of a Surface Water Supply Area identified in Rule 411.a.(1).B.i.

ii. Operators of any existing Oil and Gas Locations located within the internal buffer zone of a Surface Water Supply Area identified in Rule 411.a.(1).B.i will submit a Form 2A to the Director prior to conducting any new surface disturbing activities, or a Form 4 prior to conducting any subsequent well operations pursuant to Rule 312 or making significant changes to the Oil and Gas Operations at the existing locations.

aa. The Director will review the Form 4 and may add any conditions of approval necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources from potential impacts of the surface disturbance, subsequent well operations, or significant changes.

bb. If an Operator proposes to construct an access road, pipeline, or other necessary infrastructure, the Operator will describe the necessity of the proposed infrastructure on the Form 4, and the Director will evaluate whether the proposed infrastructure is necessary for ongoing Oil and Gas Operations.

cc. The Operator will provide the Form 4 to the administrator of all potentially impacted Public Water Systems at the same time Operator submits the Form 4 to the Director.

iii. Only the Commission may grant a variance to Rules 411.a.(2).A.i & ii. If an Operator seeks a variance from Rules 411.a.(2).A.i or ii, the Operator will consult with CDPHE and the Public Water System prior to the Commission holding a hearing to grant or deny the variance pursuant to Rule 502.b. The Commission will only grant a variance to Rules 411.a.(2).A.i or ii if the Operator demonstrates that the proposed Oil and Gas Operations and applicable Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality for the Surface Water Supply Area. If the relevant Public Water System(s) agree to waive the requirements of Rules 411.a.(2).A.i or ii, the Operator will provide evidence of the waiver to the Commission. A waiver from all relevant Public Water Systems will create a presumption that a variance will be granted if the Operator also demonstrates that Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality.

B. Intermediate Buffer Zone. After January 15, 2021, at all new and existing Oil and Gas Locations within a Surface Water Supply Area intermediate buffer zone identified in Rule 411.a.(1).B.ii, in addition to the protections required by Rule 411.a.(2).C, Operators will:

i. Contain Flowback and Stimulation fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

ii. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

iii. Inspect the Oil and Location on a daily basis, unless a Form 2A approved prior to January 15, 2021 provides for less frequent inspections pursuant to any prior Commission Rule;

iv. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

v. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

C. External Buffer Zone. After January 15, 2021, at all new and existing Oil and Gas Locations in the Surface Water Supply Area external buffer zone identified in Rule 411.a.(1).B.iii, Operators will:

i. Utilize pitless drilling systems; and

ii. Conduct baseline surface water sampling prior to drilling or completing any new Wells, or re-completing or restimulating any existing Well.

aa. **Sampling Location.** Operators will sample from the Classified Water Supply Segment immediately downgradient of the Oil and Gas Location.

bb. **Sampling Timing.** Operators will take one sample prior to drilling a Well, and at least one follow-up sample from the same location 90 days after the Wells at the Oil and Gas Location are completed.

cc. **Sampling Methods.** Operators will obtain analysis of the water samples from laboratories that maintain state or nationally accredited programs and utilize currently-applicable EPA-approved analytical methods.

dd. **Reporting Data.** Operators will submit a Form 43, Analytical Sample Submittal to the Commission containing the results of each sample analysis within 60 days of collecting the sample. Operators will simultaneously submit the Form 43 to the administrator of all potentially impacted Public Water Systems.

ee. **Analytes.** Operators will analyze samples collected pursuant to this Rule 411.a.(2).C.ii for the following constituents:

1. pH;

2. Alkalinity (total bicarbonate and carbonate as $CaCO_3$);

3. Specific conductance;

4. Major cations (calcium, iron, magnesium, manganese, potassium, sodium);

5. Major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrate as N, and phosphorus);

6. Total dissolved solids;

7. BTEX compounds (benzene, toluene, ethylbenzene, and total xylenes);

8. Diesel Range Organics (DRO – C_{10} to C_{36}) and Gasoline Range Organics (GRO – C_6 to C_{10});

9. Polycyclic Aromatic Hydrocarbons (including those listed as Organic Compounds in Soils in Table 915-1); and

10. Metals (including those listed as Metals in Soils in Table 915-1).

(3) **Consultation.** If an Operator submits a Form 2A for a proposed Oil and Gas Location within a Surface Water Supply Area identified in Rule 411.a.(1), the Operator will engage in a Formal Consultation Process with any potentially impacted Public Water System pursuant to Rule 309.g. The Formal Consultation Process will address any additional Best Management Practices that should be applied for the protection of the Public Water System. If the Public Water System determines that the proposed Oil and Gas Location may impact ephemeral streams upstream and in direct hydraulic communication with a Surface Water Supply Area, the Formal Consultation Process will address the necessity of applying setbacks or mitigation measures to ephemeral streams.

(4) **Spill and Release Notification & Emergency Response.**

A. **Applicability.** This Rule 411.a.(4) applies to Operators of all new and existing Oil and Gas Locations with a Working Pad Surface within 2,640 feet of surface water that is 15 miles or less upstream from a surface water Public Water System intake.

B. **Emergency Response Plan Requirements.** Emergency response plans maintained by Operators pursuant to Rule 602.j will include current contact information for the administrators of all Public Water Systems with a surface water intake within 15 miles downstream.

C. **Spill and Release Notification.** No later than when the Operator provides the Director with notice pursuant to Rule 912.b.(1), the Operator will notify the administrators of all Public Water Systems with a surface water intake within 15 miles downstream in the event of a Spill or Release if the Spill or Release is reportable pursuant to Rule 912.b.(1).A and has the potential to impact the Public Water System.

b. **Groundwater Under the Direct Influence of Surface Water & Type III Aquifer Wells.**

(1) **Definitions.**

A. Groundwater Under the Direct Influence of Surface Water ("GUDI") means any water beneath the surface of the ground with:

i. Significant occurrence of insects or other macro-organisms, algae, or large-diameter pathogens such as Giardia lamblia or Cryptosporidium; or

ii. Significant and relatively rapid shifts in water characteristics such as turbidity, temperature, conductivity, or pH, which closely correlate to climatological or surface water conditions.

B. Groundwater Under the Direct Influence of Surface Water Well ("GUDI Well") means a Public Water System that is supplied by a well under the direct influence of surface water.

C. Type III Aquifer means an Aquifer that consists of unconsolidated geologic material including alluvial, colluvial or other unconsolidated materials, as defined in the Colorado State Board of Examiners of Water Well Construction and Pump Installation Contractors, Rules and Regulations for Water Well Construction, Pump Installation, Cistern Installation, and Monitoring and Observation Hole/Well Construction, 2 C.C.R. § 402-2:5.2.2.3 (2020) (hereinafter "State Engineer's Water Well Construction and Permitting Rules"). Only the January 15, 2021 version of the State Engineer's Water Well Construction and Permitting Rules applies to this Rule; later amendments do not apply. All materials incorporated by reference in this Rule are available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, the State Engineer's Water Well Construction and Permitting Rules are available from the State Engineer's Office, 1313 Sherman St., Suite 821, Denver, CO 80203, and are available online at https://dwr.colorado.gov/services/well-construction-inspection#water-well-construction-rules. Type III Aquifers may contain localized impermeable layers that do not act as hydraulic boundaries between distinct Aquifers. A common example of a Type III Aquifer is an alluvial Aquifer.

D. Type III Well means a Public Water System supply well completed in a Type III Aquifer.

(2) Buffer Zones.

A. The internal buffer zone is located between 0 and 1,000 feet from a GUDI Well or Type III Well.

B. The intermediate buffer zone is located between 1,001 and 1,500 feet from a GUDI Well or Type III Well.

C. The external buffer zone is located between 1,501 and 2,640 feet from a GUDI Well or Type III Well.

(3) Protections. Operators will comply with the standards established below for the buffer zone in which the Working Pad Surface is proposed or located and with all standards for zones farther from the GUDI Well or Type III Well.

A. Internal Buffer Zone.

i. After January 15, 2021, Operators will not conduct any new surface disturbance within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).A.

ii. Only the Commission may grant a variance to Rule 411.b.(3).A.i. If an Operator seeks a variance from Rule 411.b.(3).A.i, the Operator will consult with CDPHE and the Public Water System prior to the Commission holding a hearing to grant or deny the variance pursuant to Rule 502.b. The Commission will only grant a variance to Rule 411.b.(3).A.i if the Operator demonstrates that the proposed Oil and Gas Operations and applicable Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality for the GUDI Well or Type III Well. If the relevant Public Water System(s) agree to waive the requirements of Rule 411.b.(3).A.i, the Operator will provide evidence of the waiver to the Commission. A waiver from all relevant Public Water System(s) will create a presumption that a variance will be granted if the Operator also demonstrates that Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality.

iii. Operators of new Oil and Gas Locations within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).A will adhere to all requirements for operations within the internal buffer zone of a Surface Water Supply Area pursuant to Rule 411.a.(2).A.

B. Intermediate Buffer Zone. After January 15, 2021, Operators of new Oil and Gas Locations within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).B will adhere to all requirements for operations within the intermediate buffer zone of a Surface Water Supply Area pursuant to Rule 411.a.(2).B.

C. External Buffer Zone. After January 15, 2021, Operators will utilize pitless drilling systems at all new and existing Oil and Gas Locations within the external buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).C.

(4) Consultation. If an Operator submits a Form 2A for a proposed Oil and Gas Location within 2,640 feet of a GUDI Well or Type III Well, the Operator will engage in a Formal Consultation Process with the administrator of the Public Water System that operates the GUDI Well or Type III Well pursuant to Rule 309.g. The Formal Consultation Process will address:

A. Any Best Management Practices that should be applied;

B. Whether Groundwater monitoring is necessary. Although the Operator and Public Water System may determine that Groundwater monitoring is necessary in other circumstances, at a minimum Groundwater monitoring will be necessary if:

i. The Public Water System determines that Groundwater monitoring is necessary;

ii. Installation of one or more Groundwater monitoring wells does not pose significant, unusual, or unique risks of contamination to the Aquifer; and

iii. Suitable locations for one or more Groundwater monitoring wells exist between the proposed Oil and Gas Location and the GUDI Well or Type III Well and in other appropriate locations to determine groundwater gradient; and

C. Whether protection of recharge facilities is necessary. If the Public Water System determines that the proposed Oil and Gas Location may impact engineered structures that enable recharge to the Public Water System in the vicinity of a GUDI Well or Type III Well, the Formal Consultation Process will address the necessity of applying setbacks or mitigation measures to such recharge facilities.

(5) Spill and Release Notification & Emergency Response.

A. Applicability. This Rule 411.b.(5) applies to Operators of all new and existing Oil and Gas Locations with a Working Pad Surface within 2,640 feet of a GUDI Well or Type III Well.

B. Emergency Response Plan Requirements. Emergency response plans maintained by Operators pursuant to Rule 602.j will include current contact information for the administrators of all Public Water Systems with a GUDI Well or Type III Well within 2,640 feet of the Working Pad Surface.

C. Spill and Release Notification. No later than when the Operator provides notice to the Director pursuant to Rule 912.b.(1), the Operator will notify the administrators of all Public Water Systems with a GUDI Well or Type III Well within 2,640 feet of a Spill or Release that is reportable pursuant to Rules 912.b.(1).A, F, G, or J.

(6) Reporting Groundwater Monitoring Data. If Groundwater monitoring is required pursuant to Rule 411.b.(4).B, the Operator will submit a Form 43 to report data from the monitoring well(s) for each of the analytes listed in Rule 411.a.(2).C.ii.ee at a frequency specified as a condition of approval on the Operator's Form 2A.

412. SURFACE OWNER NOTICE

a. Statutory Notice to Surface Owners. Not less than 30 days in advance of commencement of operations with heavy equipment for the drilling of a Well, Operators will provide the statutorily required notice to the Well Site Surface Owner(s) as described below and the Relevant Local Government. Notice to the Surface Owner may be waived in writing by the Surface Owner.

(1) Surface Owner Notice is not required on federal- or Indian-owned surface lands.

(2) Surface Owner Notice will be delivered by hand; certified mail, return-receipt requested; or by other delivery service with receipt confirmation. Electronic mail may be used if the Surface Owner has approved such use in writing.

(3) The Surface Owner Notice will provide:

A. The Operator's name and contact information for the Operator or its agent;

B. A site diagram or plat of the proposed Well location and any associated roads and Production Facilities;

C. The date operations with heavy equipment are expected to commence;

D. A copy of the COGCC Informational Brochure for Surface Owners; and

E. A postage-paid, return-addressed post card whereby the Surface Owner may request consultation pursuant to Rule 309.

(4) Notice of Subsequent Operations. An Operator will provide to the Surface Owner or the Surface Owner's appointed agent and the Relevant Local Government at least 7 days advance notice of subsequent operations with a rig or heavy equipment that will materially impact surface areas beyond the existing access road or Oil and Gas Location, including but not limited to all operations listed in Rule 312.a.

(5) Notice During Irrigation Season. If a Well is to be drilled on irrigated Crop Land or may interfere with other agricultural activities, the Operator will contact the Surface Owner or agent at least 14 days prior to commencement of operations with heavy equipment to coordinate drilling operations to avoid unreasonable interference with irrigation plans and agricultural activities.

(6) Final Reclamation Notice. Not less than 30 days before any final Reclamation operations are to take place pursuant to Rule 1004, the Operator will notify the Surface Owner. Final Reclamation operations will mean those Reclamation operations to be undertaken when a Well is to be Plugged and Abandoned or when Production Facilities are to be permanently removed. Such notice is required only where final Reclamation operations commence more than 30 days after the completion of a Well.

b. Move-In, Rig-Up Notice.

(1) At least 30 Days, but no more than 90 days, before moving in and rigging up a drilling rig, the Operator will provide Move-In, Rig-Up ("MIRU") Notice to all Surface Owners, Building Unit owners and tenants within 2,000 feet of the Working Pad Surface if:

A. It has been more than one year since the previous notice or since drilling activity last occurred, or

B. Notice was not previously required.

(2) The Operator may rely on the county assessor tax records to identify Building Unit Owners within 2,000 feet of the Working Pad Surface receiving the MIRU Notice.

(3) The Operator will provide notice to the physical address of all parcels of land within 2,000 feet of the Working Pad Surface receiving the MIRU Notice.

(4) MIRU Notice will be delivered by hand; certified mail, with return-receipt requested; electronic mail, with return receipt requested, delivery confirmation, or by other delivery service with delivery confirmation.

(5) The MIRU Notice will include:

A. A statement informing the Building Unit Owner and tenant that the Operator intends to move in and rig up a drilling rig to drill Wells within 2,000 feet of their Building Unit;

B. The Operator's contact information where it may be reached 24-hours a day;

C. The legal location of the proposed Wells (Quarter-Quarter, Section, Township, Range, County);

D. The approximate street address of the proposed Well locations (Street Number, Name, City);

E. The name and number of the proposed Wells, including the API Number if the Form 2 has been approved or the eForm Document Number if the Form 2 is pending approval;

F. The anticipated date (day, month, year) the drilling rig will move in and rig up;

G. The Commission's website address and telephone number; and

H. The estimated duration of time (which may be a range) that the drilling rig will be onsite and an indication of whether multiple drilling operations are planned for the Oil and Gas Location.

(6) A Surface Owner or Building Unit owner entitled to receive MIRU Notice may waive their right in writing at any time.

(7) An Operator may request an exception to this Rule and provide MIRU Notice less than 30 days prior to moving in and rigging up a drilling rig for good cause.

413. FORM 7, OPERATOR'S MONTHLY REPORT OF OPERATIONS

a. Operators will report all existing oil and gas Wells that are not Plugged and Abandoned on the Form 7, Operator's Monthly Report of Operations within 45 days after the end of each month. A Well will be reported every month from the month that it is spud until it has been reported for one month as abandoned. Each formation that is completed in a Well will be reported every month from the time that it is completed until it has been abandoned and reported for one month as abandoned. The reported volumes will include all Fluids produced during Flowback, initial testing, completion, and production of the Well.

b. Operators will report the volume of produced Fluids and any gas or Fluids used during enhanced recovery unit operations injected into a Class II UIC Well on a Form 7 within 45 days after the end of each month. Produced Fluids include, but are not limited to, produced water and Fluids recovered during drilling, casing cementing, pressure testing, completion, workover, and formation stimulation of all Wells including production, exploration, injection, service and monitoring wells.

c. Operators will report the volume of any non-produced Class II Fluids not listed in Rule 413.b injected into a Class II UIC Well on a Form 14, Monthly Report of Non-Produced Water Injected pursuant to Rule 808.b.

414. FORM 5, DRILLING COMPLETION REPORT

a. Form 5, Preliminary Drilling Completion Report.

(1) If drilling is suspended prior to reaching total depth and does not recommence within 90 days, an Operator will submit a Form 5, Preliminary Drilling Completion Report within the next 10 days.

(2) **Information Requirements.** The Form 5, Preliminary Drilling Completion Report will include the following information:

A. The date drilling activity was suspended;

B. The reason for the suspension;

C. The anticipated date and method of resumption of drilling; and

D. The details of all work performed to date, including all the information required in Rule 414.b.(2) that has been obtained.

(3) A Form 5, Final Drilling Completion Report will be submitted after reaching total depth as required by Rule 414.b.

b. Form 5, Final Drilling Completion Report.

(1) A Form 5, Final Drilling Completion Report will be submitted within 60 days of rig release after drilling, sidetracking, or deepening a Well to total depth. In the case of continuous, sequential drilling of multiple Wells on a pad, the Form 5, Final Drilling Completion Report will be submitted for all the Wells within 60 days of rig release for the last Well drilled on the pad.

(2) **Information Requirements.** The Form 5, Final Drilling Completion Report will include the following information:

A. A cement job summary for every casing string set or required by permit conditions will be attached to the form. The cement summary report will include cement reports and charts related to cement placement, which will include:

i. Daily operations summary; and

ii. Cement verification reports from the cementing contractor.

B. All Logs run, open-hole and cased-hole, electric, mechanical, mud, or other, will be reported and submitted as specified here:

i. A digital image file (PDF, TIFF, PDS, or other format approved by the Director) of every Log run will be attached to the form. The digital image file of the cement bond Log will include a variable density display.

ii. A digital data file (LAS, DLIS, or other format approved by the Director) of every Log run, with the exception of mud Logs and cement bond Logs, will be attached to the form.

C. All drill stem tests will be reported and test results will be attached to the form.

D. All cores will be reported and the core analyses attached to the form. If core analyses are not yet available, the Operator will note this on the Form 5 and provide a copy of the analyses as soon as it is available, via a Form 4.

E. Any directional survey will be attached to the form and will meet the requirements set forth in Rule 410.

F. The latitude and longitude coordinates of the as drilled Well location will be reported on the form. The latitude and longitude coordinates will be in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum (“NAD”) of 1983 (*e.g.*, latitude 37.12345, longitude -104.45632). If GPS technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 216. The Operator will report the accuracy value expressed in meters and the date of the GPS measurement on the Form 5.

G. The Bradenhead pressure action threshold, which is calculated as 30% of the TVD in feet of the surface casing shoe expressed in psig.

(3) The Operator will submit a Form 5 within 30 days of the completion of Well operations in which the casing or cement in the wellbore is changed. Changes to the wellbore casing or cement configuration include, but are not limited to, the operations listed in

Rule 408.e.(5). The Form 5 will include the information required by Rule 414.b.(2). The form will include the following attachments:

A. Daily operations summary;

B. Cement verification reports from the contractor; and

C. Cement bond Log(s) if run by Rule, choice, or as a required condition of the repair approval, submitted pursuant to Rule 414.b.(2).B.

415. COMMINGLING

a. The commingling of production from multiple formations or Wells is encouraged in order to maximize the efficient use of wellbores and to minimize the surface disturbance from Oil and Gas Operations. Commingling may be conducted at the discretion of an Operator without prior Commission approval, unless:

(1) The Operator proposes to conduct commingling at an existing Well through a procedure that requires prior Director approval pursuant to Rule 312.a; or

(2) The Commission has issued an order or promulgated a Rule excluding specific Wells, geologic formations, geographic areas, or Fields from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission's own motion.

b. This Rule 415 supersedes the procedural requirements to establish commingling and allocation contained in any Commission order as of the effective date of this Rule 415, but does not supersede any allocation made under such order.

416. FORM 5A, COMPLETED INTERVAL REPORT

a. The Operator will submit the Form 5A, Completed Interval Report for a formation within 30 days after the following operations:

(1) Any Stimulation or re-stimulation;

(2) Any Productivity Test (successful or not), if there is no Stimulation;

(3) Any reperforation or change in the perforated interval if there is no Stimulation;

(4) Commingling with another formation;

(5) Temporary abandonment; or

(6) Permanent abandonment of the formation if the Well is not to be abandoned.

b. The Operator will report the details of any Stimulation performed including, but not limited to, Hydraulic Fracturing Treatment and acidizing Stimulation.

c. In order to resolve completed interval information uncertainties, the Director may require an Operator to submit further information in an additional Form 5A.

417. MECHANICAL INTEGRITY TESTING

For the purpose of this Rule, a mechanical integrity test of a Well is a test to determine if there is a significant leak in the Well's casing, tubing, or mechanical isolation device, or if there is significant Fluid movement through vertical channels to other formations.

a. Injection Wells. A mechanical integrity test will be performed on all injection Wells.

(1) The mechanical integrity test will include one of the following tests to determine whether significant leaks are present in the casing, tubing, or mechanical isolation device:

A. Isolation of the tubing-casing Annulus with a packer set at 100 feet or less above the highest open Injection Zone perforation, unless an alternate isolation distance is approved in writing by the Director. The pressure test will be with liquid or gas at a pressure of not less than 300 psi or the average injection pressure, whichever is greater, and not more than the maximum permitted injection pressure;

B. The monitoring and reporting to the Director, on a monthly basis for 60 consecutive months, of the average casing-tubing Annulus pressure, following an initial pressure test; or

C. Any equivalent test or combination of tests approved by the Director.

(2) The mechanical integrity test will include one of the following tests to determine whether there are significant Fluid movements in vertical channels adjacent to the wellbore:

A. Cementing records which will only be valid for injection Wells in existence prior to July 1, 1986;

B. Tracer surveys;

C. Cement bond log or other acceptable cement evaluation log;

D. Temperature surveys; or

E. Any other equivalent test or combination of tests approved by the Director.

(3) No person will inject fluids via a new injection Well unless a mechanical integrity test on the Well has been performed and supporting documents including Form 21, Mechanical Integrity Test, submitted and approved by the Director. Oral approval may be granted for continuous injection following a successful test.

(4) Following the performance of the initial mechanical integrity test required by Rule 417.a.(3), additional mechanical integrity tests will be performed on each type of injection Well as follows:

A. **Class II UIC Well.** As long as it is used for the injection of Fluids, mechanical integrity tests will be performed at the rate of not less than 1 test every 5 years, except as specified by Rule 417.a.(4).C below. Five year periods will commence on the date the initial mechanical integrity test is performed or the date of a mechanical integrity test specified in Rule 417.a.(4).C below.

B. **Simultaneous Injection Well.** No additional tests will be required after the initial mechanical integrity test.

C. **All Injection Wells.** A new mechanical integrity test will be performed after any casing repairs, after resetting the tubing or mechanical isolation device, or whenever the tubing or mechanical isolation devise is moved during workover operations.

(5) All injection Well mechanical integrity tests will be witnessed by the Director.

b. Shut-in Wells. All Shut-in Wells will pass a mechanical integrity test.

(1) A mechanical integrity test will be performed on each Shut-in Well within 2 years of the initial shut-in date.

(2) Subsequently, a mechanical integrity test will be performed on each Shut-in Well on 5-year intervals from the date the initial mechanical integrity test was performed, as long as the Well remains shut-in.

(3) The mechanical integrity test for a Shut-in Well will be performed after isolating the wellbore with a bridge plug or similar approved isolating device set 100 feet or less above the highest open perforation. The pressure test will be with liquid or gas at an initial, stabilized surface pressure of not less than 300 psi surface pressure or any equivalent test or combination of tests approved by the Director.

(4) Not less than 48 hours prior to returning an inactive, Shut-In Well to production or injection, an Operator will submit a Form 42 – Notice of Return to Service, to the Director of the scheduled date for returning the Well to production or injection to allow the Commission to inspect.

c. Temporarily Abandoned Wells. All Temporarily Abandoned Wells will pass a mechanical integrity test.

(1) A mechanical integrity test will be performed on each Temporarily Abandoned Well within 30 days of temporarily abandoning the well.

(2) Subsequently, a mechanical integrity test will be performed on each Temporarily Abandoned Well on 5 year intervals from the date of the initial mechanical integrity test was performed, as long as the Well remained temporarily abandoned.

(3) The mechanical integrity test for a Temporarily Abandoned Well will be performed after isolating the wellbore with a bridge plug or similar approved isolating device set 100 feet or less above the highest open perforation. The pressure test will be liquid or gas at an initial, stabilized surface pressure of not less than 300 psi surface pressure or any equivalent test or combination of tests approved by the Director.

(4) Not less than 48 hours prior to returning an inactive, Temporarily Abandoned Well to production or injection, an Operator will submit a Form 42 – Notice of Return to Service, to the Director of the scheduled date for returning the Well to production or injection to allow the Commission to inspect the installation of equipment or conduct of the mechanical intervention.

d. Suspended Operations and Waiting on Completion Wells. A mechanical integrity test will be performed on Suspended Operations Wells and Waiting On Completion Wells as described in this Rule 417.d.

(1) A mechanical integrity test will be performed on each Suspended Operations Well within 2 years of setting any casing string and suspending operations prior to reaching permitted total depth.

(2) A mechanical integrity test will be performed on each Waiting On Completion Well within 2 years of setting production casing.

(3) Subsequently, a mechanical integrity test will be performed on each Suspended Operations Well and Waiting On Completion Well on 5 year intervals from the date that the initial mechanical integrity test was performed, as long as the Well remains in a suspended operations or waiting on completion status.

(4) The mechanical integrity test for a Suspended Operations Well and Waiting On Completion Well will be performed to verify integrity of the casing string being tested. The pressure test will be liquid or gas at an initial, stabilized surface pressure of not less than 300 psi surface pressure or any equivalent test or combination of tests approved by the Director.

e. Not less than 10 days prior to the performance of any mechanical integrity test required by this Rule 417, any person required to perform the test will notify the Director with a Form 42 – Mechanical Integrity Test, of the scheduled date and time when the test will be performed.

f. All Wells will maintain mechanical integrity. All Wells which lack mechanical integrity, as determined through a mechanical integrity test, or other means, will be repaired or Plugged and Abandoned within 6 months. If an Operator has performed a mechanical integrity test within the 2 years required for Shut-in Wells or the 30 days required for Temporarily Abandoned Wells by this Rule, the Operator will have 6 months from the date of the unsuccessful test to make repairs or Plug and Abandon the Well. If the Operator has not performed a mechanical integrity test within the required time frames in Rules 417.b.(1) & c.(1), the Operator will not be given an additional 6 months in the event of an unsuccessful test.

g. Mechanical integrity test pressure loss or gain will not exceed 10% of the initial stabilized surface pressure over a test period of 15 minutes. The test may be repeated if the pressure loss or gain is determined to be the result of compression related to gas dissolution from the Fluid column or temperature effects related to the Fluid used to load the column. Wells that do not satisfy this test requirement are considered to lack mechanical integrity and are subject to the requirements of Rule 417.f.

418. FORM 21, MECHANICAL INTEGRITY TEST

a. Results of all mechanical integrity tests, including tests that show a lack of integrity, will be submitted on Form 21, Mechanical Integrity Test, within 30 days after the test.

b. A mechanical integrity test that shows the Well lacks integrity is considered a failed test.

c. The Form 21 will be completely filled out except for Part II, which is required only for injection Wells. An original copy of the pressure chart will be submitted with every Form 21.

419. BRADENHEAD MONITORING, TESTING, AND REPORTING

a. Equipment Requirements.

(1) The Operator will equip Bradenhead access on all Wells to the Annulus between the production and surface casing as well as any intermediate casing with appropriate fittings to allow safe and convenient determination of pressure and Fluid flow.

(2) To allow for Commission visual inspection at all times, all valves used for annular pressure monitoring will remain exposed and will not be buried. An Operator may use a rigid housing to protect the valves so long as the housing can be easily opened or removed by the Operator upon request.

(3) These equipment requirements apply to all Wells, regardless of function.

b. Bradenhead Monitoring. The Operator will monitor all Wells at a Director-indicated frequency for aspects of Well integrity necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, including Groundwater, Potential Flow Zones, and formations and pursuant to this Rule 419.

(1) **After Rig Release, Prior to Stimulation.** An Operator will monitor all annular casing pressures on a monthly basis. If at any point the Bradenhead monitoring pressure is greater than 30% of the TVD in feet of the surface casing shoe expressed in psig, the Operator will contact the Director before proceeding with Stimulation to determine whether mitigation or other measures are necessary to ensure isolation consistent with the Commission's Rules.

(2) **During Hydraulic Fracturing Treatment.**

A. An Operator will confine the placement of all Stimulation fluids to the objective formations during Hydraulic Fracturing Treatment to the extent practicable.

B. During Hydraulic Fracturing Treatment operations, an Operator will continuously monitor and record Bradenhead Annulus pressure on all Wells being Stimulated.

C. If intermediate casing has been set on the Well Stimulated by Hydraulic Fracturing Treatment, an Operator will monitor and record the pressure in the Annulus between the intermediate casing and the production casing during Stimulation operations.

D. During Hydraulic Fracturing Treatment operations, an Operator will monitor the Bradenhead Annulus and casing pressures for all Wells within 300 feet of the wellbore being Stimulated.

E. If at any time during Hydraulic Fracturing Treatment operations, the Bradenhead Annulus pressure in psig in the Well being Stimulated or any Well being monitored has a Bradenhead pressure exceeding 30% of the TVD in feet of the surface casing shoe expressed in psig, or the Operator has reason to suspect any potential failure of the production casing or Stimulation string, the Operator will:

i. Safely and quickly discontinue the Stimulation and dissipate the annular pressure.

ii. Notify the Director as soon as practicable but no later than 24 hours following the occurrence with a Form 42 – Notice of High Bradenhead Pressure During Stimulation.

iii. Perform diagnostic testing on the Well and related equipment as is necessary to determine: (i) whether such a failure has actually occurred; (ii) if the pressure observations can be accounted for due to thermal expansion or pressure "ballooning" of the casing; or (iii) the presence or absence of a downhole failure or whether a migration pathway has actually occurred. The

Operator will perform diagnostic testing as soon as is reasonably practical after Operator has reasonable cause to know of or suspect any such failure.

aa. If the Operator does not identify a downhole failure or a migration pathway, the Operator will notify the Director of the results. The Director will timely grant approval to proceed with stimulation and may do so orally.

bb. If the Operator identifies a downhole failure or migration pathway, the Operator will consult with the Director and, upon request, provide and implement a corrective plan prior to continuing any further Stimulation operations on the Well and any additional Well on the Oil and Gas Location.

iv. Submit a Form 4, providing all details, including whether a downhole failure or migration pathway occurred, cause of the high pressure or suspected failure, and corrective measures taken within 15 days after the occurrence.

(3) **Thirty Days After Hydraulic Fracturing Treatment.** For the first 30 days after Hydraulic Fracturing Treatment or completion, an Operator will monitor and record production casing pressure and all annular casing pressures for a Well on a daily basis, at a minimum.

(4) **Through the Remaining Life of the Well.** For all Wells in the state, an Operator will monitor and record production casing pressure and all annular casing pressures on a monthly basis or at a Director-approved frequency. If a Well's Bradenhead pressure is greater than 30% of the TVD in feet of the surface casing shoe expressed in psig, or a lower threshold set by a Commission order, or if a Well flows liquids or continuous gas from the Bradenhead Annulus, an Operator will:

A. Report the Bradenhead pressure to the Director on a Form 17, Bradenhead Test Report;

B. Take immediate action to remedy such an annular pressure; and

C. Perform diagnostic testing to determine if the annular casing pressure is sustained. An Operator will report diagnostic testing results to the Director on a Form 4 within 60 days of submitting a Form 17 pursuant to Rule 419.b.(4).A. If the diagnostic testing confirms sustained casing pressure, an Operator will develop and implement a pressure management plan and provide the plan with the Form 4.

(5) **Records.** An Operator will keep Bradenhead monitoring records required by Rule 419.b available for inspection by the Director for a minimum of 5 years after the monitoring was performed.

c. **Annual Bradenhead Testing and Reporting.** For all Wells other than coalbed methane Wells, an Operator will perform an annual Bradenhead test and submit the data to the Director on a Form 17 or other Director-approved method. For coalbed methane Wells, an Operator will perform Bradenhead testing pursuant to Rule 614.e.

d. **Bradenhead Test Observations.**

(1) If an Operator observes a deficiency, the Operator will immediately take action to address the deficiency. Actions taken may include the Operator performing diagnostic testing on the Well to determine whether a deficiency does exist and the best method of repair or if a pressure management plan is needed.

(2) The Director may impose a remediation plan if a deficiency exists, and if imposed, the Operator will implement an approved remediation plan or pressure management plan and report results within 30 days or as required by the approved plan.

(3) If the Operator is not able to effectively address the deficiency or implement a pressure management plan, the Operator will Plug and Abandon the Well within 6 months of discovering the deficiency.

420. FORM 17, BRADENHEAD TEST REPORT

The Operator will submit results of Bradenhead tests to the Director within 10 days of completing the test either by filing a Form 17, Bradenhead Test Report or by another method approved by the Director or Commission. The Operator will include a wellbore diagram if not previously submitted or if the wellbore configuration has changed. The Director may request that the Operator collect samples for analysis of the Bradenhead gas and liquid along with production gas. The Operator will submit the results of any gas and liquid analysis collected using a Form 43.

421. STATEWIDE FLOODPLAIN REQUIREMENTS

a. When operating within a defined Floodplain, the following requirements apply to new Oil and Gas Locations and Wells:

(1) Effective August 1, 2015, Operators will notify the Director when a new proposed Oil and Gas Location is within a defined Floodplain, via the Form 2A.

(2) Effective June 1, 2015, new Wells will be equipped with remote shut-in capabilities prior to commencing production. Remote shut-in capabilities include, at a minimum, the ability to shut-in the Well from outside the relevant Floodplain.

(3) Effective June 1, 2015, new Oil and Gas Locations will have secondary containment areas around Tanks constructed with a synthetic or geosynthetic liner that is mechanically connected to the steel ring or another engineered technology that provides equivalent protection from floodwaters and debris.

b. When operating within a defined Floodplain, the following requirements apply to all Wells, Tanks, separation equipment, containment berms, Production Pits, Special Purpose Pits, and Flowback Pits:

(1) Operators will maintain a current inventory of all existing Wells, Tanks, and separation equipment in a defined Floodplain. Operators will ensure that a list of all such Wells, Tanks, and separation equipment is filed with the Director. As part of this inventory, Operators will maintain a current and documented plan describing how Wells within a defined Floodplain will be timely shut-in. This plan will include what triggers will activate the plan and will be made available for inspection by the Director upon request.

(2) All Tanks, including partially buried Tanks, and separation equipment will be anchored to the ground. Anchors will be engineered to support the Tank and separation equipment and to resist flotation, collapse, lateral movement, or subsidence.

(3) Containment berms around Tanks will be constructed of steel rings or another engineered technology that provides equivalent protection from floodwaters and debris.

(4) Production Pits, Special Purpose Pits (other than Emergency Pits), and Flowback Pits containing E&P Waste are prohibited within a defined Floodplain.

422. LOCAL GOVERNMENT WELFARE PROTECTION STANDARDS

Operators will comply with all Relevant Local Government requirements, including regulations that may be more protective or stricter than the Commission's Rules.

423. NOISE

a. Operators will submit a noise mitigation plan that demonstrates one or more proposed methods of meeting the maximum permissible noise levels described by this Rule 423 as an attachment to their Form 2As, as required by Rule 304.c.(2). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 423.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. The noise mitigation plan will include at least the following information:

(1) An explanation of how the Operator will comply with the maximum permissible noise levels specified in Rule 423.b.(1). This is to include a description of methods to design acoustical mitigation measures or choose/site equipment appropriately such that the Operator has a reasonable expectation of compliance.

(2) Estimated duration of each stage of operation, including drilling, completion, Flowback, production, and an estimate of the noise levels of each stage of operation;

(3) Reference to topographical considerations of noise and noise propagation at the proposed Oil and Gas Location;

(4) Description of Best Management Practices and best engineering practices for measuring and mitigating noise levels and an implementation schedule for such technology.

(5) For proposed Oil and Gas Locations with a Working Pad Surface within 2,000 feet of one or more Residential Building Units, at least one, and no more than six noise points of compliance where monitors will be located. Operators will identify noise points of compliance using the following criteria:

A. Provide one noise point of compliance in each direction in which a Residential Building Unit is located within 2,000 feet of the proposed Working Pad Surface.

B. Noise points of compliance will be located at least 350 feet from the Working Pad Surface, and no less than 25 feet from the exterior wall of the Residential Building Unit that is closest to the Working Pad Surface. If a Surface Owner or tenant refuses to provide the Operator with access to install a noise monitor, then the noise point of compliance will be located at either the next-closest Residential Building Unit or an alternative location approximately the same distance and direction from the Working Pad Surface.

b. A preliminary plan for how the Operator will conduct background ambient noise surveys to establish baseline conditions for noise levels on the site, for both A-scale and C-scale noise. The Director may require as a condition of approval on the Form 2A that the Operator conduct the background ambient noise survey between 30 and 90 days prior to start of construction and update the plan accordingly based on the results. Operators will conduct baseline noise surveys at the noise points of compliance identified pursuant to Rule 423.a.(5). When an Operator conducts a background ambient survey the Operator will follow the same approach as outlined in Rule 423.c.(7) and over a 72-hour period, including at least 24 hours between 10:00 p.m. on a Friday and 4:00 a.m. on a Monday. Operators will record any significant weather events and take those events into account when establishing the baseline. A single cumulative daytime ambient noise level and a single cumulative nighttime ambient noise level will be established by taking the logarithmic average of all daytime or nighttime 1-hour Leq values measured and in accordance with the sound level data collection requirements pursuant to the maximum permissible noise levels.

(1) All Oil and Gas Operations will comply with the following maximum permissible noise levels in Table 423-1 unless otherwise required by Rule 423. The Director may require Operators to comply with a lower maximum permissible noise level based on the consultation process with Relevant and Proximate Local Governments, CDPHE, or CPW pursuant to Rules 302.g, 309.e, & 309.f.

Table 423-1 – Maximum Permissible Noise Levels

LAND USE DESIGNATION	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential/ Rural/State Parks & State Wildlife Areas	55 db(A)	50 db(A)
Commercial/Agricultural	60 db(A)	55 db(A)
Light Industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)
All Zones	60 db(C)	60 db(C)

(2) Unless otherwise required by Rule 423, drilling or completion operations, including Flowback:

A. In Residential/Rural or Commercial/Agricultural, maximum permissible noise levels will be 60 db(A) in the hours between 7:00 p.m. to 7:00 a.m. and 65 db(A) in the hours between 7:00 a.m. to 7:00 p.m.; and

B. In all zones maximum permissible noise levels will be 65 db(C) in the hours between 7:00 p.m. to 7:00 a.m. and 65 db(C) in the hours between 7:00 a.m. to 7:00 p.m.

(3) The basis for determining land use designation pursuant to Table 423-1 will be the Relevant Local Government's land use or zoning designation. The Director may consult with a Relevant or Proximate Local Government to identify the type of land use of the Oil and Gas Location and its surrounding area, taking into consideration any applicable zoning or other local land use designation.

A. To protect public health, safety, and welfare, the Director may require Operators to comply with a lower maximum permissible noise level in areas zoned industrial, light industrial, or commercial, if the Oil and Gas Facility will be within 2,000 feet of a Residential Building Unit or High Occupancy Building Unit.

B. In a noise mitigation plan submitted pursuant to Rule 423.a, an Operator may request a higher maximum permissible noise level than would otherwise be allowed by Table 423-1, if the Operator demonstrates that both the Relevant and any Proximate Local Governments agree to the higher maximum permissible noise level. The Director may apply that higher maximum permissible noise level as long as the requested level is protective of public health, safety, and welfare, and wildlife.

(4) When operating in High Priority Habitat, Operators will consult CPW and, on federal lands, the Bureau of Land Management, or United States Fish and Wildlife Service, to determine the acceptable noise limits and monitoring protocols.

(5) Operators may exceed the noise levels in Table 423-1 as measured at the nearest noise point of compliance if all affected Surface Owners and tenants agree in writing to the higher noise limit requested by the Operator.

(6) Unless otherwise required by Rule 423.b.(7), during the hours between 7:00 a.m. and the next 7:00 p.m. the maximum permissible noise levels listed in Table 423-1 may be increased 10 dB(A) for a period not to exceed 15 minutes in any 1-hour period. The increase is permissible only for a 1 hour period during any 12 hours.

(7) Operators will reduce periodic, impulsive, or shrill noise by 5 dB(A) below the levels in Table 423-1. For periodic, shrill, and impulsive noise within 1000 feet of a Residential Building Unit, Operators will minimize noise that can be readily eliminated through maintenance, equipment modification, or other readily available procedures.

(8) Pursuant to Commission inspection or upon receiving a complaint from a Local Government, or a Surface Owner or tenant of a property within 2,000 feet of an Oil and Gas Facility regarding noise related to Oil and Gas Operations, the Commission will conduct an onsite investigation and take sound measurements using the methods prescribed for Operators in Rule 423.c.

c. To demonstrate compliance with Tables 423-1 and 423-2 Operators will measure sound levels according to the following standards:

(1) During pre-production activities and ongoing operations lasting longer than 24 consecutive hours such as drilling, completion, recompletion, Stimulation, and Well maintenance, in areas zoned residential or within 2,000 feet of a Building Unit, Operators will take continuous sound measurements from each noise point of compliance designated pursuant to Rule 423.a.(5).

(2) Monitoring Procedures.

A. In response to a complaint or at the Director's request, Operators will measure sound levels at 25 feet from the complainant's occupied structure towards the noise source for low frequency (dbC) indicated issues. For high frequency (dbA) measurement will be at the nearest point of compliance. For equipment installed at Oil and Gas Locations subject to a Form 2A approved prior to January 15, 2021, after the Commencement of Production Operations, no single piece of equipment will exceed the maximum permissible noise levels listed in Table 423-1 as measured at a point 350 feet from the equipment generating the noise in the direction from which the complaint was received.

B. In situations where measurement of noise is unrepresentative due to topography or any other issue, Operators or the Commission may take the measurement at the nearest noise point of compliance, or at a different distance and extrapolate it to 25 feet from the complainant's residence (dbC) or the complainant's property line (dbA) using the following formula:

db(A) distance 2 = db(A) distance 1 – 20 x log 10 (distance 2/distance 1)

$$db(C)\ distance\ 2 = db(C)\ distance\ 1 - 20 \times \log 10\ (distance\ 2/distance\ 1)$$

(3) Operators will equip sound level meters with wind screens that are in good working order, and will take readings when the wind velocity at the time and place of measurement is not more than 5 miles per hour. In determining an Oil and Gas Operation's contribution to sound levels, the Director will consider wind readings that exceed 5 mph.

(4) Operators will take sound level measurements 5 feet above ground level.

(5) Operators will determine sound levels by averaging logarithmic minute-by-minute measurements made over a minimum 1-hour sample duration.

(6) All sound meters will be type II meters at a minimum. All measurements will be reported using LeqA (fast) and LeqC (slow). Meters will be field calibrated pre-survey and post survey. Continuous surveys will be field calibrated pre-survey and post survey and pursuant to the manufacturer's recommended interval. All survey equipment will be inspected at time of calibration for compliance with the Commission's Rules.

(7) Operators will take samples under conditions that are representative of the noise experienced by the complainant (*e.g.*, at night, morning, evening, or during special weather conditions).

(8) If a Building Unit, High Occupancy Building Unit, High Priority Habitat, or Designated Outside Activity Area is built or designated after an Oil and Gas Development Plan or Form 2A is approved, the Operator of the Oil and Gas Location need not comply with Rule 423.c with respect to the newly built or designated Building Unit, High Occupancy Building Unit, High Priority Habitat, or Designated Outside Activity Area.

(9) Operators will maintain records to demonstrate compliance with this Rule 423.c, and will submit the records to the Director upon request.

d. Cumulative Noise. All noise measurements will be cumulative.

(1) Noise measurements taken at noise points of compliance designated pursuant to Rule 423.a.(5) will take into account ambient noise, rather than solely the incremental increase of noise from the facility targeted for measurement.

(2) At new or substantially modified Oil and Gas Locations where ambient noise levels at noise points of compliance designated pursuant to Rule 423.a.(5) already exceed the noise thresholds identified in Table 423-1, then Operators will be considered in compliance with Rule 423, unless at any time their individual noise contribution, measured pursuant to Rule 423.c, increases noise above ambient levels by greater than 5 dBC and 5 dBA between 7:00 p.m. and 7:00 a.m. or 7 dBC and 7 dBA between 7:00 a.m. and 7:00 p.m. This Rule 423.d.(2) does not allow Operators to increase noise above the maximum cumulative noise thresholds specified in Table 423-2 after the Commencement of Production Operations.

(3) After the Commencement of Production Operations, if ambient noise levels already exceed the maximum permissible noise thresholds identified in Table 423-1, under no circumstances will new Oil and Gas Operations or a significant modification to an existing Oil and Gas Operations raise cumulative ambient noise above:

Table 423-2 – Maximum Cumulative Noise Levels

LAND USE	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential /Rural/State Parks/State Wildlife Areas	65 db(A)	60 db(A)
Commercial/Agricultural	70 db(A)	65 db(A)
Light Industrial	80 db(A)	75 db(A)
Industrial	90 db(A)	85 db(A)
All Zones	75 db(C)	70 db(C)

e. If Oil and Gas Operations result in persistent noise that adversely impacts public welfare, the Director may require the Operator to take action pursuant to Rule 901.a.

424. LIGHTING

a. Operators will submit a light mitigation plan as an attachment to their Form 2As, pursuant to Rule 304.c.(3). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 424.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent.

(1) All light mitigation plans will be signed by a person with relevant expertise in light mitigation techniques and design.

(2) All light mitigation plans will address:

A. A pre-production facility lighting plan demonstrating one or more proposed methods of ensuring compliance with Rule 424.c, and:

i. That provides adequate lighting to ensure safety during active operations involving personnel; and

ii. The proposed anticipated location, mounting, height, and orientation of all outdoor lighting fixtures on the site during pre-production activities.

iii. Nothing in this Rule 424.a.(2).A prevents an Operator from using ad hoc temporary portable lighting when necessary for safety reasons during pre-production activities, provided that the Operator otherwise complies with the standards in Rules 424.b–f.

B. A Production Facility lighting plan demonstrating one or more proposed methods of ensuring compliance with Rules 424.d & e, and:

i. The location, mounting, height, and orientation of all outdoor lighting fixtures on the site;

ii. A table that calculates the total lumen output of all fixtures combined; and

iii. Cut sheets of light fixtures that demonstrate Backlight, Uplight, and Glare (“BUG”) rating, lumen output, and fully shielded design; and

iv. For any location with a Building Unit within 2,000 feet, a photometric plan estimating or calculating the illuminance, measured in lux, 100 feet outside the facility boundary;

C. The Operator's capability of meeting all requirements of this Rule 424 through one or more proposed methods;

D. The location of the resources and receptors listed in Rules 424.c & d; and

E. Square footage of the Working Pad Surface for purposes of demonstrating compliance with Rule 424.d.(2).

b. Lighting Standards.

(1) Operators will direct site lighting downward and inward, such that no light shines above a horizontal plane passing through the center point light source.

(2) Operators will use appropriate technology within fixtures that obscures, blocks, or diffuses the light to reduce light intensity outside the boundaries of the Oil and Gas Facility.

(3) Operators will use Best Management Practices to minimize light pollution and obtrusive lighting, which may include, but are not limited to:

A. Minimizing lighting when not needed using timers or motion sensors;

B. Using full cut-off lighting;

C. Using lighting colors that reduce light intensity; and

D. Using low-glare or no-glare lighting.

c. Pre-Production Facility Lighting.

(1) At all Oil and Gas Facilities with active operations involving personnel, Operators will provide sufficient on-site lighting to ensure the safety of all persons on or near the site.

(2) If the facility has a noise barrier, Operators will locate the facility lighting beneath the noise barrier, except for drilling rig lights, which will be shielded and pursuant to Federal Aviation Administration permit requirements if applicable. Operators will take precautions to ensure that lights do not shine out of openings in the noise barrier.

(3) Prior to the Commencement of Production Operations, Operators will take all necessary and reasonable precautions to ensure that lighting from Oil and Gas Facilities does not unnecessarily impact the health, safety, and welfare of any of the following:

A. Persons occupying Building Units within 2,000 feet of the Oil and Gas Facility;

B. Motorists on roads within 2,000 feet of the Oil and Gas Facility; and

C. Wildlife occupying any High Priority Habitat within 2,000 feet of the Oil and Gas Facility.

d. Production Phase Facility Lighting When Personnel Are On-Site.

(1) After the Commencement of Production Operations, at all Oil and Gas Facilities with active operations involving personnel, Operators will provide sufficient on-site lighting to ensure the safety of all persons on or near the site.

(2) After the Commencement of Production Operations, when active operations involving personnel are occurring, Oil and Gas Facilities will not exceed the following maximum permissible light levels.

LAND USE	**Lumens per square foot of Working Pad Surface**
Residential /Rural/State Parks/State Wildlife Areas/High Priority Habitat/Wilderness Areas/National Park/National Monument	1.25
Commercial/Agricultural	2.5
Light Industrial	5.0
Industrial	7.5

(3) The basis for determining land use designation pursuant to be Rule 424.d.(2) will be the Relevant Local Government's land use or zoning designation. The Director may consult with a Relevant or Proximate Local Government to identify the type of land use of the Oil and Gas Location and its surrounding area, taking into consideration any applicable zoning or other local land use designation.

A. To protect public safety and welfare, the Director may require Operators to comply with a lower maximum permissible light level in areas zoned industrial, light industrial, or commercial, if the Oil and Gas Facility will be within 2,000 feet of a Residential Building Unit or High Occupancy Building Unit.

B. The Director may require Operators to comply with a lower maximum permissible light level based on the consultation process with Relevant and Proximate Local Governments, CDPHE, or CPW required by Rules 302.g, 309.e, & 309.f.

C. In a light mitigation plan submitted pursuant to Rule 424.a, an Operator may request a higher maximum permissible light level than would otherwise be allowed by Rule 424.d.(2), if the Operator demonstrates that both the Relevant and any Proximate Local Governments agree to the higher maximum permissible light level. The Director may apply that higher maximum permissible light level as long as the requested level is protective of public safety, public welfare, and wildlife.

e. Production Phase Facility Lighting When Personnel Are Not On-Site. After the Commencement of Production Operations, Operators will minimize continuous on-site lighting when personnel are not present.

f. Cumulative Light Impacts. Operators will develop site lighting to reduce cumulative nighttime light intensity from all Oil and Gas Facilities to 4 lux at any Residential Building Unit or High Occupancy Building Unit within 1 mile of any Oil and Gas Facility, measured at 5.5 feet above grade in a direct line of sight to the brightest light fixture onsite.

425. VISUAL IMPACT MITIGATION

a. Commission Visual Impact Mitigation Standards.

(1) Unless the Commission approves an alternate method of visual impact mitigation, all permanent equipment at new and existing Oil and Gas Facilities, regardless of construction date, which are observable from any public highway, road, or publicly-maintained trail, will be painted with uniform, non-contrasting, non-reflective color tones (similar to the Munsell Soil Color Coding System), and with colors matched to but slightly darker than the surrounding landscape.

(2) If requested to do so during consultation with the Relevant Local Government, the Surface Owner, or a Building Unit owner pursuant to Rules 302.g, 309.b, or 309.c, an Operator will orient new Oil and Gas Facilities in a direction to reduce the contrast between the Oil and Gas Facilities and the surrounding landscape. If multiple receptors to visual impacts may be present, the Operator will describe its efforts to use orientation to minimize impacts on all potential receptors.

b. Oil and Gas Facilities located on the surface of federal lands will be painted and oriented as directed by the appropriate federal agency.

c. Operators will use Best Management Practices to avoid, minimize, and mitigate visual impacts consistent with any Relevant Local Government's regulations.

426. ODORS

a. For proposed Working Pad Surfaces within 2,000 feet of a Building Unit or Designated Outside Activity Area, Operators will submit an odor mitigation plan as an attachment to their Form 2As, as required by Rule 304.c.(4). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 426.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. All odor mitigation plans will address:

(1) How the Operator will comply with all requirements of this Rule 426 through one or more proposed methods; and

(2) All Best Management Practices the Operator will use to reduce odors.

b. Operators will conduct all Oil and Gas Operations at all Oil and Gas Facilities in a manner that minimizes odors outside the boundaries of the Oil and Gas Location.

c. In areas within 2,000 feet of a Building Unit or Designated Outside Activity Area, Operators will use current and appropriate Best Management Practices to minimize odors.

d. Complaint System.

(1) Upon Director request, the Operator(s) of the Oil and Gas Facility or Facilities subject to the complaint will provide within 24 hours the Director, the Relevant or Proximate Local Government, and the complainant (should the complainant request notification) with a complete description of all activities occurring at the facility during the timeframe specified in the complaint.

(2) The Director may require the Operator(s) of the Oil and Gas Facility or Facilities subject to the complaint to take necessary and reasonable actions to reduce odors, including, but not limited to, conducting air sampling to measure volatile organic compounds.

e. **Cumulative Odors.** The Commission or Director may require Operators to adopt additional Best Management Practices as conditions of approval or through guidance to minimize odors in areas with high concentrations of oil and gas activities that may expose one or more Building Units or Designated Outside Activity Areas to odors from oil and gas sources.

427. DUST

a. Operators will submit a dust mitigation plan for all Oil and Gas Operations on Oil and Gas Locations and lease access roads, that demonstrates one or more methods of meeting the requirements of this Rule 427 as an attachment to their Form 2As, as required by Rule 304.c.(5). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 427.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. Such plans will include at least the following information:

(1) Soil type;

(2) Proposed vehicle speed limit to minimize dust;

(3) Total area of soil disturbance (in acres);

(4) Whether access roads are paved;

(5) Number of anticipated truck trips during each stage of wellpad construction, drilling, completion, and production;

(6) A plan for suppressing fugitive dust caused solely by wind; and

(7) A list of Best Management Practices that will be used. Such practices may include, but are not limited to:

A. The use of speed restrictions;

B. Regular road maintenance; and

C. Restricting construction activity during high wind days.

b. Operators will minimize fugitive dust caused by their operations, or dust originating from areas disturbed by their Oil and Gas Operations that becomes windborne.

(1) If at any time, an Operator is not in compliance with this Rule 427.b, the Operator will cease ongoing truck traffic or other operations causing fugitive dust, until the Operator has performed dust suppression activities that the Director determines substantially and adequately control dust. If an Operator disagrees with the Director’s determination, it may appeal to the Commission pursuant to Rule 901.a.(3).

(2) Compliance with a dust minimization plan submitted pursuant to Rule 427.a does not relieve an Operator of complying with this Rule 427.b.

c. Applying Dust Suppressant.

(1) Operators will not use any of the following fluids for dust suppression:

A. Produced water;

B. E&P Waste or hazardous waste;

C. Crude oil or any oil not specifically designed for road maintenance;

D. Solvents; and

E. Any process Fluids.

(2) Operators will use only fresh water (potable or non-potable) to conduct dust suppression activities within 300 feet of the ordinary high-water mark of any water body.

(3) Operators will maintain safety data sheets ("SDS") for any chemical-based dust suppressant, and make the SDS available immediately upon request to the Director and to the Local Government. Operators will maintain SDS for any chemical-based dust suppressant until the site passes final site Reclamation, and transfer the records upon transfer of property ownership.

d. Within 2,000 feet of Building Units, or High Priority Habitat, the Commission may require additional dust control measures as a condition of approval, including, but not limited to:

(1) Constructing wind breaks and barriers;

(2) Automation of Wells to reduce truck traffic;

(3) Road or facility surfacing; and

(4) Soil stockpile stabilization measures.

e. Cumulative Dust Impacts. Based on review of dust mitigation plans submitted pursuant to Rule 427.a, the Commission may require Operators to adopt additional dust mitigation requirements to reduce cumulative dust impacts, based on the following considerations:

(1) The number of anticipated truck trips for the Oil and Gas Facility seeking Commission approval combined with the number of anticipated truck trips at any other Oil and Gas Locations within a 1-mile radius during the same time period;

(2) Whether the truck traffic for the Oil and Gas Facility seeking Commission approval will use any of the same unpaved roads as truck traffic for any other Oil and Gas Facility; and

(3) Whether there are other major sources of dust in the area, which may or may not be Oil and Gas Facilities, which will result in the area bearing a cumulative dust risk that could harm public health, safety, welfare, the environment, or wildlife resources, including impacts to plants, such as burial or significant damage to photosynthetic processes.

428. WELL CONTROL

a. The Operator will take all reasonable precautions, in addition to fully complying with Rule 417 to prevent any oil, gas or water well from flowing uncontrolled during Well operations and will take immediate steps and exercise due diligence to bring under control any such Well.

b. For controlled drilling events, a "significant" Well control event is a kick managed by shutting in the Well to circulate out the kick.

c. **Form 23, Well Control Report.** The Operator will report all uncontrolled events and any significant controlled events during a Well operation to the Director as soon as practicable, but no later than 24 hours following the incident. Within 15 days after these occurrences, the Operator will submit a Form 23, Well Control Report.

d. If required, the Operator will submit a Form 19, Spill/Release Report, for reportable Spills or Releases providing all details required on the form.

429. MEASUREMENT OF OIL

a. **General Standards.**

(1) **Measurement and Recording.** The volume of all oil production from a lease or a production unit will be measured and recorded prior to removal from the lease or production unit. The volume of production of oil will be computed in terms of Barrels of clean oil on the basis of properly calibrated meter measurements or Tank measurements of oil-level differences, made and recorded to the nearest 1/4 inch of 100% capacity tables, subject to the following corrections in Rules 429.b & c below.

(2) **Incorporation by Reference.** This Rule 429 will be used consistently with standards established by the ASTM International ("ASTM"), the American Petroleum Institute ("API") Manual of Petroleum Measurement Standards, the American Gas Association ("AGA"), GPA Midstream ("GPA"), or other applicable standards-setting organizations, and pursuant to contractual rights or obligations. Only those editions of standards in effect as of January 15, 2021 apply to this Rule, later amendments do not apply. All materials incorporated by reference in this Rule 429 are available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. The materials may also be examined at any state publications depository library if the materials are not available online for free. In addition, these materials are available from the organizations at:

A. ASTM, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959; https://www.astm.org/.

B. API, 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571; https://www.api.org/.

C. AGA, 400 North Capitol Street, NW, Suite 450, Washington, DC 20001; https://www.aga.org/.

D. GPA, 6060 American Plaza, Suite 700, Tulsa, OK 74135, https://gpamidstream.org/.

b. **Correction for Impurities.** The percentage of impurities (water, sand, and other foreign substances not constituting a natural component part of the oil) will be determined to the satisfaction of the Director, and the observed gross volume of oil will be corrected to exclude the entire volume of such impurities.

c. Temperature Correction. The observed volume of oil corrected for impurities will be further corrected to the standard volume of sixty degrees Fahrenheit (60° F) pursuant to ASTM D1250-19e1, Standard Guide for Use of the Joint API and ASTM Adjunct for Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils (May 1, 2019), as incorporated by reference pursuant to Rule 429.a.(2) ("ASTM D1250"), or any close approximation thereof approved by the Director.

d. Gravity Determination. The gravity of oil at 60° F will be determined pursuant to Table 5 of ASTM D-1250, as incorporated by reference in Rule 429.c, or any close approximation thereof approved by the Director.

e. Tank Gauging. Measurement by Tank gauging will be completed pursuant to industry standards as specified in:

(1) API, Manual of Petroleum Measurement Standards, Chapter 3.1A: Standard Practice for the Manual Gauging of Petroleum and Petroleum Products (Third Edition, December 2018), as incorporated by reference pursuant to Rule 429.a.(2);

(2) API, Manual of Petroleum Measurement Standards, Chapter 3.1B: Standard Practice for the Manual Gauging of Petroleum and Petroleum Products (Third Edition, April 2018), as incorporated by reference pursuant to Rule 429.a.(2);

(3) API, Manual of Petroleum Measurement Standards, Chapter 18.1: Custody Transfer, Section 1: Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck (Third Edition, May 2018), as incorporated by reference pursuant to Rule 429.a.(2); or

(4) API, Manual of Petroleum Measurement Standards, Chapter 18.2: Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods (First Edition, July 2016), as incorporated by reference pursuant to Rule 429.a.(2).

f. Metering Station. Measurement will be completed pursuant to industry standards as specified in the following chapters of the API Manual of Petroleum Measurement Standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 4: Proving Systems:

A. Chapter 4.2: Displacement Provers (Third Edition, September 2003, reaffirmed March 2011); and

B. Chapter 4.8: Operation of Proving Systems (Second Edition, September 2013);

(2) API, Manual of Petroleum Measurement Standards, Chapter 5: Metering:

A. Chapter 5.1: General Considerations for Measurement by Meters (Fourth Edition, September 2005, reaffirmed July 2016, including June 2008 and June 2011 errata);

B. Chapter 5.2: Measurement of Liquid Hydrocarbons by Displacement Meters (Third Edition, October 2005, reaffirmed July 2015);

C. Chapter 5.3: Measurement of Liquid Hydrocarbons by Turbine Meters (Fifth

Edition, September 2005, reaffirmed August 2014, including July 2009 Addendum 1);

D. Chapter 5.4: Accessory Equipment for Liquid Meters (Fourth Edition, September 2005, reaffirmed August 2015, including May 2015 errata);

E. Chapter 5.5: Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems (Second Edition, July 2005, reaffirmed August 2015); and

F. Chapter 5.6: Measurement of Liquid Hydrocarbons by Coriolis Meters (First Edition, October 2002, reaffirmed November 2013);

(3) API, Manual of Petroleum Measurement Standards, Chapter 7: Temperature Determination:

A. Chapter 7.1: Liquid-in-Glass Thermometers (Second edition, August 2017);

B. Chapter 7.2: Portable Electronic Thermometers (Third edition, May 2018);

C. Chapter 7.3: Fixed Automatic Tank Temperature Systems (Second edition, October 2011, reaffirmed December 2016); and

D. Chapter 7.4: Dynamic Temperature Measurement (Third edition, January 2018);

(4) API, Manual of Petroleum Measurement Standards, Chapter 8: Sampling:

A. Chapter 8.1: Standard Practice for Manual Sampling of Petroleum and Petroleum Products (Fifth Edition, September 2019); and

B. Chapter 8.2: Standard Practice for Automatic Sampling of Petroleum and Petroleum Productions (Fourth Edition, November 2016); and

(5) API, Manual of Petroleum Measurement Standards, Chapter 12, Calculation of Petroleum Quantities:

A. Chapter 12.1.1: Calculation of Static Petroleum Quantities, Part 1—Upright Cylindrical Tanks and Marine Vessels (Fourth Edition, February 2019).

g. LACT Meters. Measurement utilizing LACT units will be pursuant to industry specifications or standards as specified in API, Manual of Petroleum Measurement Standards, Chapter 6.1, Lease Automatic Custody Transfer (LACT) Systems (Second Edition, May 1991, reaffirmed December 2017), as incorporated by reference pursuant to Rule 429.a.(2).

h. Sales Reconciliation. In order to facilitate the resolution of questions regarding the payment of proceeds or sales reconciliation from a Well, a payee may submit a Form 37, Payment of Proceeds – Sales Volume Reconciliation Payer Contact Form to the payer requesting additional information concerning the payee’s interest in the Well, price of the oil sold, taxes applied to the sale of oil, differences in Well production and Well sales, and other information as described in § 34-60-118.5, C.R.S. The payer will return the completed form to the payee within 60 days of receipt. Submittal of this form to the payer will fulfill the requirement for “written request” described in § 34-60-118.5(2.5), C.R.S., and is a prerequisite to filing a complaint with the Commission. The payer will use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

i. A Form 37 requesting information concerning payment of proceeds or sales volume reconciliation may be submitted by the payee at any time. The Commission may act to prohibit or terminate any abuse of the reconciliation process.

j. Meter Calibration.

(1) Meters will be calibrated annually unless more frequent calibration is required by contractual obligations or by the Director. All calibration reports will be created, maintained, and made available as operation records pursuant to Rule 206. In the event two consecutive meter calibrations exceed a 2% error, the Operator will report the test results to the Director who may require the Operator to show cause why the meter should not be replaced.

(2) The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times.

430. MEASUREMENT OF GAS

a. General Standards.

(1) **Measurement and Reporting.** The volume of all gas produced from a lease or a production unit will be measured and recorded prior to removal from the lease or production unit. Production of gas of all kinds will be measured by meter unless otherwise agreed to by the Director. For computing volume of gas to be reported to the Commission, the standard pressure base will be 14.73 psia, regardless of atmospheric pressure at the point of measurement, and the standard temperature base will be 60° F. All volumes of gas to be reported to the Commission will be adjusted by computation to these standards, regardless of pressures and temperatures at which the gas was actually measured, unless otherwise authorized by the Director.

(2) **Incorporation by Reference.** This Rule 430 will be used consistently with standards established by the ASTM, API, AGA, GPA, or other applicable standards-setting organizations, as incorporated by reference pursuant to Rule 429.a.(2), and pursuant to contractual rights and obligations.

b. Metering Station. Installation and operation of gas measurement stations will be pursuant to industry standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 14.3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-Edged Orifice Meters:

A. Part 2: Specification and Installation Requirements (Fifth Edition, March 2016 including March 2017 and January 2019 errata);

B. Part 3: Natural Gas Applications (Fourth Edition, November 2013); and

C. Part 4: Background, Development, Implementation Procedure, and Example Calculations (Fourth Edition, October 2019);

(2) API, Manual of Petroleum Measurement Standards, Chapter 21.1: Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement (Second Edition, February 2013);

(3) AGA, Report #7: Measurement of Natural Gas by Turbine Meters (January 2006);

(4) AGA, Report #9: Measurement of Gas by Multipath Ultrasonic Meters (July 2017); and

(5) AGA, Report #11: Measurement of Natural Gas by Coriolis Meter (February 2013).

c. Metering Equipment. The devices used to measure the differential, line pressure, and temperature will have accepted accuracy ratings established in industry standards as specified in API, Manual of Petroleum Measurement Standards, Chapter 22: Testing Protocols, as incorporated by reference pursuant to Rule 429.a.(2):

(1) Chapter 22.1: General Guidelines for Developing Testing Protocols for Devices Used in the Measurement of Hydrocarbon Fluids, (Second Edition, August 2015, including November 2018 Addendum 1); and

(2) Chapter 22.2: Testing Protocols—Differential Pressure Flow Measurement Devices (Second Edition, April 2017).

d. Meter Calibration.

(1) Meters will be calibrated annually unless more frequent calibration is required by contractual obligations or by the Director. All calibration reports will be created, maintained, and made available as operation records pursuant to Rule 206. In the event two consecutive meter calibrations exceed a 2% error, the Operator will report the test results to the Director who may require the Operator to show cause why the meter should not be replaced.

(2) The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times.

e. Gas Quality. The heating value of produced natural gas will be representative of the flowing gas stream at the lease or unit boundary, as determined by chromatographic analysis of a sample obtained in close proximity to the volume measurement device and will be reported on a Form 7. Gas sampling and analysis will occur annually unless more frequent sampling is required by contractual obligations or by the Director. Gas sampling, gas chromatography, and the resulting analysis data will be pursuant to industry standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 14.1: Collecting and Handling of Natural Gas Samples for Custody Transfer (Seventh Edition, May 2016, including August 2017 Addendum 1 and Errata 1);

(2) GPA, Standard 2166, Obtaining Natural Gas Samples for Analysis by Gas Chromatography (Fifth Edition, January 2017);

(3) GPA, Standard 2261, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2019 Edition, January 2019);

(4) GPA, Standard 2286, Method for the Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography (September 2014);

(5) GPA, Standard 2145, Table of the Physical Properties for Hydrocarbons and Other Compounds of Interest to Natural Gas and Natural Gas Liquids Industries (January

2016); and

(6) GPA, Standard 2172, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (February 2020).

f. **Sales Reconciliation.** In order to facilitate the resolution of questions regarding the payment of proceeds or sales reconciliation from a Well, a payee may submit a Form 37 to the payer requesting additional information concerning the payee's interest in the Well, price of the gas sold, taxes applied to the sale of gas, differences in Well production and Well sales, and other information as described in § 34-60-118.5, C.R.S. The payer will return the completed form to the payee within 60 days of receipt. Submittal of this form to the payer will fulfill the requirement for "written request" described in § 34-60-118.5(2.5), C.R.S., and is a prerequisite to filing a complaint with the Commission. The payer will use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

g. A Form 37 requesting information concerning payment of proceeds or requesting information concerning sales volume reconciliation may be submitted by the payee at any time. The Commission may act to prohibit or terminate any abuse of the reconciliation process.

431. MEASUREMENT AND REPORTING OF PRODUCED, REUSED, RECYCLED, AND INJECTED WATER

a. The volume of produced water will be computed and reported in terms of Barrels on the basis of properly calibrated meter measurements or Tank measurements of water-level differences, made and recorded to the nearest 1/4 inch of 100% capacity tables, or another method approved by the Director. If measurements are based on oil/water ratios, the oil/water ratio will be based on a production test performed during the last calendar year. Other equivalent methods for measurement of produced water may be approved by the Director. The volume of produced water will be reported on the Form 7.

b. On the Form 5 and the Form 5A Operators will report the volume in Barrels of the following Fluids used in drilling operations and Stimulation, respectively:

(1) Total Fluids;

(2) Fresh water; and

(3) Recycled or reused Fluids that offset the use of fresh water.

c. The volume of water injected into a Class II UIC Well will be computed and reported in term of Barrels on the basis of properly calibrated meter measurements or Tank measurements of water-level differences made and recorded to the nearest 1/4 inch of 100% capacity tables, or another method approved by the Director. If water is transported to an injection facility by means other than direct Pipeline, measurement of water is required by a properly calibrated meter. The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times. The volume of injected water will be reported on the Form 7.

d. The volume of water injected and produced in Simultaneous Injection Wells will be computed and reported in terms of Barrels on the basis of calculated pump volumes, on the basis of property calibrated meter measurements, or on the basis of a produced gas to water ratio based on an annual production test. The volumes of injected and produced water will be reported on the Form 7.

432. VACUUM PUMPS ON WELLS

a. The installation of vacuum pumps or other devices for the purpose of imposing a vacuum at the wellhead or on any oil or gas bearing reservoir may be approved by the Director upon application therefore, except as herein provided. The application will be accompanied by an exhibit showing the location of all Wells on adjacent premises and all offset Wells on adjacent lands, and will set forth all material facts involved and the manner and method of installation proposed. Notice of the application will be given by the Applicant by registered or certified mail, or by delivering a copy of the application to each producer within 1/2 mile of the installation.

b. If no objection to a Rule 432.a application is filed by a producer within 1/2 mile of the installation, or by the Director, within 15 days of the date of application, the Director will approve the application. If an objection is filed by any producer within 1/2 mile of the installation, or the Director, the application will be brought to the Commission for hearing pursuant to Rule 510.

433. USE OF GAS FOR ARTIFICIAL GAS LIFTING

Gas may be used for artificial gas lifting of oil where all such gas returned to the surface with the oil is used without waste. Where the returned gas is not to be so used, the use of gas for artificial gas lifting of oil is prohibited unless otherwise specifically ordered and authorized by the Commission upon hearing.

434. ABANDONMENT

The requirements for abandoning a Well are as follows:

a. Plugging.

(1) An Operator will plug a dry or abandoned Well, seismic, core, or other exploratory hole, in such a manner that oil, gas, water, or other substance will be confined to the formation in which it originally occurred, isolating all zones specified in Rule 408.e, and zones identified and approved on the Form 6, Well Abandonment Report – Notice of Intent to Abandon. If the wellbore is not static before setting a plug in an open hole or after casing is removed from the wellbore, then the Operator will circulate any produced Fluids from the wellbore and will fill the wellbore with wellbore Fluids sufficient to maintain a balance or overbalance of the producing formation. Wellbore Fluids will be in a static state prior to pumping balanced cement plugs, unless the Operator is placing the cement plug as a preliminary step to counteract a high pressure or a lost circulation zone before establishing a static state. The Operator will fill intervals between plugs with wellbore Fluids of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. If mud is necessary to maintain wellbore Fluids in a static state prior to setting plugs, the Operator will use a minimum mud weight of 9 pounds per gallon. The Operator will use water spacers both ahead of and behind balanced plug cement slurry to minimize cement contamination by any wellbore Fluids that are incompatible with the cement slurry. Any cement plug will be a minimum of 100 feet in length and will extend a minimum of 100 feet above each zone to be isolated. The material an Operator uses in plugging, whether cement, mechanical plug, or some other equivalent method approved in writing by the Director, will be placed in the Well in a manner to permanently prevent migration of oil, gas, water, or other substance from the formation in which it originally occurred. Cement will conform to the requirements in Rule 408.f. The Operator will ensure the slurry design achieves a minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours measured at 95° Fahrenheit, or at the minimum expected downhole temperature, and at 800 psi confining pressure.

(2) The Operator will have the option as to the method of placing cement in the hole by (a) dump bailer, (b) pumping a balanced cement plug through tubing or drill pipe, (c) pump and plug, or (d) equivalent method approved by the Director prior to plugging. Unless prior approval is given, all wellbores will have water, mud, or other approved Fluid between all plugs.

(3) An Operator will not place substances of any nature or description other than that normally used in plugging operations in any Well at any time during plugging operations. An Operator will submit all final reports of Plugging and Abandonment on a Form 6 and include an operations summary or cement verification report from the plugging contractor, specifying the type of Fluid used to fill the wellbore, type and slurry volume of API Class cement used, date of work, and depth the plugs were placed.

(4) An Operator may not pull surface casing from any Well unless authorized by the Director.

(5) All abandoned Wells will have a plug or seal placed in the casing and all open annuli from a depth of 50 feet to the surface of the ground or the bottom of the cellar in the hole in such manner as not to interfere with soil cultivation or other surface use. For below-grade markers, the Operator will fit the top of the casing with a screw cap or a steel plate welded in place with a weep hole. For above-grade markers, the Operator will fit the top of the casing with a screw cap or a steel plate welded in place with a weep hole, and a permanent monument that will be a pipe not less than four inches in diameter and not less than 10 feet in length, of which four feet will be above ground level and the remainder embedded in cement or welded to the surface casing. Whether a below-grade or an above-grade marker is used, the Operator will inscribe the marker with the Well's legal location, Well name and number, and API Number. The Operator will not cap or seal the Well until 5 days after placing the last plug to allow monitoring for successful plugging and will cap or seal the Well within 90 days after placing the last plug.

(6) The Operator will obtain approval from the Director of the plugging method prior to plugging, and will notify the Director of the estimated time and date the plugging operation of any Well is to commence, and identify the depth and thickness of all known sources of Groundwater. The Operator will verify the placement of the plug required at the base of Groundwater and the placement of any other plug specified by the Director by tagging or by an alternative method approved by the Director. For good cause shown, the Director may require that a cement plug be tagged if a cement retainer or bridge plug is not used. If requested by the Operator, the Director will furnish written follow-up documentation for a requirement to tag cement plugs.

(7) **Wells Converted for Water Supply.** When the Well, seismic, core, or other exploratory hole to be plugged may safely be used as a water supply well, and such utilization is desired by the Surface Owner, the well need not be filled above the required sealing plug set below Groundwater; provided that written authority for such use is secured from the Surface Owner and, in such written authority, the Surface Owner assumes the responsibility to plug the well upon its abandonment as a water well pursuant to the Commission's Rules. Such written authority and assumption of responsibility will be filed with the Commission, provided further that the Surface Owner furnishes a copy of the permit for a water well approved by the Division of Water Resources.

b. Temporary Abandonment.

(1) A Well may be temporarily abandoned after passing a successful mechanical integrity test pursuant to Rule 417 upon approval of the Director, for a period not to exceed 6 months provided the hole is cased or left in such a manner as to prevent migration of oil, gas, water, or other substance from the formation or horizon in which it originally occurred. All Temporarily Abandoned Wells will be closed to the atmosphere with a swedge and valve or packer, or other approved method. The Well sign will remain in place. If an Operator requests temporary abandonment status in excess of 6 months the Operator will state the reason for requesting such extension and state plans for future operation. A Form 4, or other form approved by the Director, will be submitted annually stating the method the Well is closed to the atmosphere and plans for future operation. Subsequent mechanical integrity tests will be required at the frequency specified in Rule 417.

(2) The manner in which the Well is to be maintained should be reported to the Commission, and bonding requirements, as provided for in the Commission's 700 Series Rules, kept in force until the permanent Plugging and Abandonment of the Well.

(3) An Operator will abandon any Well that has ceased production or injection and is incapable of production or injection and any hole determined to be dry within 6 months thereafter unless the Well passes a successful mechanical integrity test pursuant to Rule 417, and the time is extended by the Director upon application by the Owner. The application will indicate why the Well is temporarily abandoned and future plans for utilization. In the event the Well is covered by a blanket bond, the Director may require an individual plugging bond on the Temporarily Abandoned Well. Subsequent mechanical integrity tests will be required at the frequency specified in Rule 417. Gas Storage Wells are to be considered active at all times unless physically plugged.

435. FORM 6, WELL ABANDONMENT REPORTS

a. Form 6, Notice of Intent to Abandon. Prior to the abandonment of a Well, a Form 6, Well Abandonment Report – Notice of Intent to Abandon will be submitted to, and approved by, the Director. The Form 6 – Notice of Intent to Abandon will be completed and attachments included to fully describe the proposed abandonment operations. This includes the proposed depths of mechanical plugs and casing cuts; the proposed depths and volumes of all cement plugs; the amount, size and depth of casing and junk to be left in the Well; the volume, weight, and type of Fluid to be left in the wellbore between cement or mechanical plugs; and the nature and quantities of any other materials to be used in the plugging. The Operator will provide a current wellbore diagram and a wellbore diagram showing the proposed plugging procedure with the Form 6. If the Well is not plugged within six months of approval, the operator will file a new Form 6 – Notice of Intent to Abandon.

(1) The Director may add any conditions of the approval to a Form 6 – Notice of Intent to Abandon that are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director will review the Oil and Gas Location where the Well is located to ensure that necessary and reasonable conditions of approval are applied to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(3) Notice Requirements. An Operator will provide notice of plugging operations to the Surface Owner pursuant to Rule 412.a.(4).

b. Form 6, Subsequent Report of Abandonment.

(1) Within 30 days after abandonment, the Form 6, Well Abandonment Report – Subsequent Report of Abandonment will be filed with the Director. The abandonment details will include an account of the manner in which the abandonment or plugging work was performed. Copies of any casing pressure test results and downhole Logs run during Plugging and Abandonment will be submitted with the Form 6. Additionally, plugging verification reports detailing all procedures are required. A plugging verification report will be submitted for each person or contractor actually setting the plugs. The Form 6 – Subsequent Report of Abandonment and the plugging verification reports will detail the depths of mechanical plugs and casing cuts, the depths and volumes of all cement plugs, the amount, size, and depth of casing and junk left in the Well, the volume and weight of Fluid left in the wellbore, and the nature and quantities of any other materials used in the plugging. Plugging verification reports will conform with the Operator's report and both will show that plugging procedures are at least as extensive as those approved by the Director.

(2) The Director will review an Operator's Form 6 – Subsequent Report of Abandonment, plugging records, and the Well file to evaluate the abandonment or plugging work performed. The Director will approve the form or identify deficiencies for the Operator to correct and may require one of the following:

A. Surface or subsurface monitoring programs after the Well has been plugged and abandoned, if a subsurface or surface Release occurred or may occur;

B. Re-entering the Well to perform remedial cement work or Plugging and Abandonment work; or

C. Any other actions necessary to ensure proper Plugging and Abandonment of the Well.

(3) If the Operator does not take actions necessary to correct deficiencies, the Director may issue a corrective action pursuant to Rule 210.

c. Re-Plugging. A Form 6 – Notice of Intent to Abandon will be submitted to, and approved by, the Director pursuant to Rules 435.a.(1)–(3) prior to the re-entry of a Plugged and Abandoned Well for the purpose of re-plugging the Well. A Form 6 – Subsequent Report of Abandonment will be filed with the Director within 30 days of the completion of the re-plugging operations. These forms will be submitted with all the information required above and any additional information required by current policy.

d. As-Drilled Location. For all Wells being plugged, the Operator will report the latitude and longitude coordinates of the "as drilled" Well location on the Form 6. When plugging a Well for which this data has been obtained and submitted to the Commission previously, the Operator will submit this data on the Form 6 – Notice of Intent to Abandon. When plugging a Well for which this data has not yet been obtained and submitted to the Commission, the Operator will determine the "as drilled" location prior to plugging and submit the location on the Form 6 – Subsequent Report of Abandonment. The latitude and longitude coordinates will be in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum ("NAD") of 1983 (*e.g.*, latitude 37.12345, longitude -104.45632). If the Operator uses GPS technology to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 216. The

Operator will report the accuracy value expressed in meters and the date of the GPS measurement on the Form 6.

436. SEISMIC OPERATIONS, NOTICE, CONSULTATION AND REPORTING

a. Surface Owner and Tenant Notice. At least 5 business days prior to commencing Seismic Operations, the Operator will notify all Surface Owners and tenants of the lands included within the seismic project boundary.

(1) Notice will include:

A. A description of the work being performed;

B. A detailed schedule of the operations;

C. Phone numbers that are monitored 24/7 and email addresses for the company and contractors performing the work; and

D. All safety precautions employed by the Operator and any safety precautions and information that Surface Owners and tenants should be aware of.

(2) Operators will provide notice to each Surface Owner or tenant individually by letter or door hanger.

(3) Operators are encouraged to post notice of planned Seismic Operations on neighborhood, community, or municipal websites. Operators are also encouraged to coordinate notice through Relevant Local Governments, home-owners' associations, or neighborhood associations. However, such additional notice will not relieve the Operator of its responsibilities under Rule 436.a.

b. Utility Owner Notice and Consultation. Prior to the commencement of any Seismic Operation, Operators will notify and consult with owners of all subsurface utilities, including gas service lines, gas transmission lines, electric, phone, cable, water, storm sewer, sanitary sewer, fiber optic lines, water wells, or other buried utilities in the area.

(1) Operators will locate all utilities prior to performing the survey.

(2) Operators will meet or consult with the utility operator to determine safe peak vibration limits (when vibroseis will be used) and setback distances from buried utilities. Operators will retain documentation demonstrating that they consulted with all utility Operators and that the utility agreed to specific peak vibration limits and setback distances (both laterally and vertically) for the utilities.

c. Upon a request from the Director, and within 5 days of said request, Operators will provide documentation demonstrating that they complied with Rules 436.a. & b.

d. Vibration Limits.

(1) Operators will determine in advance safe setback distances from both surface structures and subsurface utilities and structures.

(2) Operators will perform real time monitoring during vibroseis operations to verify and document that variable particle velocity versus frequency standards published in the U.S. Bureau of Mines, Report of Investigations 8507 (November 1980) are not exceeded. Only the 1980 version of U.S. Bureau of Mines' Report of Investigations

8507 applies; later versions do not apply. U.S. Bureau of Mines' Report of Investigations 8507 is available for inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, U.S. Bureau of Mines' Report of Investigations 8507 may be examined at the U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, 3 Parkway Center Pittsburgh, PA 15220, and is available at https://www.osmre.gov/resources/blasting/docs/USBM/RI8507BlastingVibration1989.pdf.

(3) Unless a lower limit is required by a utility owner or a Relevant Local Government, a peak vibration limit of 0.75 inches per second ("ips") will apply to surface structures and 2.0 ips will apply to subsurface utilities and structures.

e. Seismic Operations Requiring the Drilling of Shotholes.

(1) **Explosive Storage.** Operators will safely store and account for all explosives pursuant to local, state, and federal rules.

(2) **Blasting Safety Setbacks.** Operators will keep blasting a safe distance from a Building Unit, water well, or spring, according to the following minimum setback distances:

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
0	2	200
2	5	300
5	6	360
6	7	420
7	8	480
8	9	540
9	10	600
10	11	649
11	12	696
12	13	741
13	14	784
14	15	825
15	16	864
16	17	901
17	18	936

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
18	19	969
19	20	1000
20	n/a	1320

(3) Prior to any shothole drilling, the Operator will contact the Utility Notification Center of Colorado (CO 811).

(4) **Drilling and Plugging.** Operators will adhere to the following standards for plugging shotholes unless the Operator obtains a variance pursuant to Rule 502 by demonstrating that another method will provide adequate protection to Groundwater quality and movement and long-term land stability:

A. Any slurry, drilling Fluids, or cuttings which are deposited on the surface around the seismic hole will be raked or otherwise spread out to at least within 1 inch of the surface, such that the growth of the natural grasses or foliage will not be impaired.

B. All shotholes will be preplugged or anchored to prevent public access if not immediately shot.

i. If a preplug does not hold, seismic holes will be properly Plugged and Abandoned as soon as practical after the shot has been fired. In no case will Operators leave a shothole unplugged for more than 30 days without the Director's approval.

ii. Shotholes will not be left open. Operators will cover shotholes with a tin hat or other similar cover until it can be properly plugged. The hats will be imprinted with the seismic contractor's name or identification number or mark.

C. Operators will fill holes to a depth of approximately 3 feet below ground level by returning the cuttings to the hole and tamping the returned cuttings to ensure the hole is not bridged.

i. Operators will set a non-metallic perma-plug either imprinted or tagged with the Operator's name or the identification number or mark described in the Form 20, Permit to Conduct Seismic Operations at a depth of 3 feet.

ii. Operators will fill the remaining hole and tamp it to the surface with cuttings and native soil. Operators will leave a sufficient mound of native soil over the hole to allow for settling.

D. If Operators encounter non-artesian Groundwater while drilling seismic shotholes:

i. Operators will fill the holes from the bottom up with a high-grade coarse ground bentonite to 10 feet above the static water level or to a depth of 3 feet from the surface.

ii. Operators will fill the remaining hole and tamp it to the surface with cuttings and native soil, unless the Operator otherwise demonstrates to the Director's satisfaction that use of another suitable plugging material may be substituted for bentonite without harm to Groundwater resources.

E. If artesian Groundwater (Groundwater rising above the depth at which encountered) is encountered in the drilling of any seismic hole, cement or high grade coarse ground bentonite will be used to seal off the water flow with the selected material placed from the bottom of the hole to the surface or at least 50 feet above the top of the water-bearing material, thereby preventing cross-flow between Groundwater, erosion, or contamination of fresh water supplies. Such holes will be plugged immediately.

f. Form 20A, Completion Report for Seismic Operations.

(1) If any portion of the seismic project is conducted, the Operator will submit a Form 20A, Completion Report for Seismic Operations to the Director within 60 days after completion of the permitted seismic project.

(2) The Form 20A will include the following:

A. A map in a suitable size and scale to show the actual project boundary, energy source locations, and receiver locations with sections, townships, and ranges, county and municipal boundaries, and High Priority Habitat.

B. GIS data for the actual project boundary, energy source points, and receiver locations in a format approved by the Director.

C. The results of the real time monitoring required by Rule 436.d.(2).

(3) If the program included any shotholes, the Form 20A will include:

A. Any shotholes encountering artesian water on the map;

B. A certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by the Commission's Rules; and

(4) If the permitted seismic project is not conducted prior to the expiration of the Form 20, the Operator will submit a Form 20A within 30 days of said expiration certifying that no Seismic Operations were conducted. If an Operator submits a Refile Form 20 within 30 days of the expiration of the Form 20, a Form 20A certifying no Seismic Operations were conducted is not required.

g. Financial Assurance Requirements. The Operator will file Financial Assurance pursuant to Rule 705 prior to submitting the Form 20. The Financial Assurance will remain in effect until the following conditions have been met:

(1) The Operator has submitted and the Director has approved the Form 20A for all Seismic Operations covered by the Financial Assurance;

(2) All shotholes have been properly Plugged and Abandoned, and all surface disturbance has been reclaimed pursuant to Rule 436.h;

(3) All complaints received from Surface Owners have been investigated, addressed, and resolved by the Director pursuant to Rule 524;

(4) The Operator has submitted a written request for release of Financial Assurance to the Director; and

(5) The Reclamation required by Rule 436.h has been completed.

h. Reclamation Requirements. Upon completion of Seismic Operations, the Operator will restore the surface of the land as nearly as possible to its original condition at the commencement of Seismic Operations. Appropriate Reclamation of disturbed areas will vary depending upon site-specific conditions and may include compaction alleviation and revegetation. All flagging, stakes, cables, cement, mud sacks, trash, or other materials associated with Seismic Operations will be removed.

437. Hydraulic Fracturing Chemical Additives.

a. Effective Date. After January 15, 2021, Operators will not use the chemicals listed in Table 437-1 as additives in Hydraulic Fracturing Fluid.

b. This Rule 437 does not prevent Operators from recycling or reusing produced water that has naturally occurring, trace amounts of chemicals listed in Table 437-1.

c. For any chemical constituent listed in Table 437-1 for which Table 915-1 also provides a standard, the concentration in recycled or reused produced water will be below the Table 915-1 standard, or the unconcentrated naturally occurring background level, whichever is greater.

TABLE 437-1. Chemical Additives Prohibited in Hydraulic Fracturing Fluid

Ingredient Name	CAS #
Benzene	71-43-2
Lead	7439-92-1
Mercury	7439-97-6
Arsenic	740-38-2
Cadmium	7440-43-9
Chromium	7440-47-3
Ethylbenzene	100-41-4
Xylene	1330-20-7
1,3,5-trimethylbenzene	108-67-8
1,4-dioxane	123-91-1
1-butanol	71-36-3
2-butoxyethanol	111-76-2
N,N-dimethylformamide	68-12-2
2-ethylhexanol	104-76-7
2-mercaptoethanol	60-24-2
benzene, 1,1'-oxybis-,tetrapropylene derivatives, sulfonated, sodium salts (BOTS)	119345-04-9
butyl glycidyl ether	8-6-2426
Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides (QAC)	61789-77-3
Bis hexamethylene triamine penta methylene phosphonic acid (BMPA)	35657-77-3
Diethylenetriamine penta (methylene- phosphonic acid) (DMPA)	15827-60-8
FD&C blue no. 1	3844-45-9
Tetrakis (triethanolaminato) zirconium (IV) (TTZ)	101033-44-7