

SAFETY AND FACILITY OPERATIONS REGULATIONS 600 SERIES

601. INTRODUCTION

The Commission's Rules in this 600 Series are promulgated to protect the health, safety, and welfare of the general public during all Oil and Gas Operations. They do not apply to practices regulated by the federal Occupational Safety and Health Act of 1970. For information about safety regulations applicable to industry personnel, contact the U.S. Department of Labor, Occupational Safety and Health Administration ("OSHA"), Regional Administrator, Colorado Region VIII, 1244 Speer Blvd, Suite 551, Denver, CO 80204, 720-264-6550, or visit <https://www.osha.gov/contactus/bystate/CO/areaoffice>.

602. GENERAL SAFETY REQUIREMENTS

Operators will operate and maintain all Oil and Gas Facilities in a safe manner. Operators will train their employees in the safe conduct of all job responsibilities, including safe operation and location of all equipment. An Operator will ensure that all contractors, subcontractors, and persons directly under the Operator's control on an Oil and Gas Location or at an Oil and Gas Facility receive adequate training and are aware of the hazards presented by the Operator's Oil and Gas Operations.

- a. Operators will familiarize their employees, contractors, and subcontractors with the Commission's Rules as they relate to the person's job functions.
- b. Operators are responsible for training all employees so that operations can be conducted in a safe and workmanlike manner at all times. Such training will include at a minimum the review and training on standard operating procedures and best management practices for each job function.
- c. Operators are responsible for ensuring that operations are conducted with due regard for the safety of employees, for the preservation and conservation of property, and for protecting and minimizing adverse impacts to public health, safety, welfare, the environment, and wildlife resources.
- d. Operators will establish and maintain a written operations safety management program for all Oil and Gas Operations. The operations safety management program will establish operational practices and procedures for safety and will include at a minimum a:
 - (1) Change management program; and
 - (2) Pre-Startup safety program for all new and existing Oil and Gas Locations.
- e. Employees, contractors, and subcontractors will immediately report unsafe and potentially dangerous conditions to their supervisor and any such conditions will be remedied as soon as practicable.
- f. In the event of a situation that requires operations to cease due to an imminent threat to safety, the Director may order a safety shut-in of an Oil and Gas Location until the imminent threat to safety is resolved. If the Director requires an Operator to take action pursuant to Rule 602.f, the Operator may appeal the Director's decision to the Commission pursuant to Rule 503.g.(10). The matter will not be assigned to an Administrative Law Judge pursuant to Rule 503.h. The Commission will hear the appeal at its next regularly scheduled meeting. Operators will continue to comply with any requirements identified by the Director pursuant to Rule 602.f until the Commission makes a decision on the appeal. The Commission may uphold the

Director's decision if the Commission determines the Director had reasonable cause to determine that an Operator's actions posed an imminent threat to safety, and that the action required by the Director was necessary and reasonable to address those impacts or threatened impacts. If an Operator does not appeal the Director's decision pursuant to this Rule 602.f, the Director will report the decision at its next regularly scheduled hearing.

- g.** Operators will notify the Director and the Local Government of the applicable jurisdiction of reportable safety events at an Oil and Gas Facility. Reportable safety events include:

 - (1)** Any accidental fire, explosion, detonation, uncontrolled release of pressure, or loss of Well control, vandalism or terrorist activity, or any accidental or natural event that damages equipment or otherwise alters an Oil and Gas Facility so as to create a significant Spill or Release, fire hazard, unintentional public access, or any other condition that threatens public safety;
 - (2)** Any accident or natural event at an Oil and Gas Facility that results in a reportable injury as defined by the U.S. Department of Labor, Occupational Safety and Health Administration ("OSHA"), 29 C.F.R. § 1904.39 (2021). Only the January 15, 2021 version of OSHA's 29 C.F.R. § 1904.39 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, CO 80203. In addition, 29 C.F.R. § 1904.39 (2021) is available from OSHA's Office of Regional Administrator, Colorado Region VIII, 1244 Speer Blvd, Suite 551, Denver, CO 80204, and is available online at <https://www.osha.gov/laws-regs/regulations/standardnumber/1904/1904.39>;
 - (3)** Any Spill or Release of hazardous Chemicals reportable to another state or federal agency, or a Grade 1 Gas Leak; and
 - (4)** Any accident or natural event at an Oil and Gas Facility that results in:

 - A.** An injury to a member of the general public that requires medical treatment; or
 - B.** Damage to lands, structures, or property on or off the Oil and Gas Location.
- h.** Operators will provide initial notification of a reportable safety event described in Rule 602.g.(1)–(4) above, as soon as practicable, but no more than 6 hours after the safety event. A Form 22, Accident Report, will be submitted to the Director within 3 days of the reportable safety event.

 - (1)** At the Director's request, the Operator will submit a supplemental report that details the root cause, information about any repairs, or other information related to the accident.
 - (2)** At the Director's request, the Operator will present its root cause report about the accident to the Commission or to an oil and gas safety review organization approved by the Director.
- i.** Where unsafe or potentially dangerous conditions exist at an Oil and Gas Location and first responders or Commission Staff are on-site, the Operator will respond to and be present at the Location with first responders or Commission Staff.
- j.** Each Operator will have a functioning emergency response plan that provides for the effective management of situations that may arise from Oil and Gas Operations. All existing and proposed Oil and Gas Locations will have an emergency response plan in place that has been coordinated with, and approved by, the local emergency response agency. The plan may be developed to cover all Oil and Gas Locations within a Field or geographical area so long as the emergency response agency agrees.

- (1) After the initial emergency response plan has been coordinated with, reviewed by, and approved by the local emergency response agency, the emergency response plan will then be reviewed and updated at intervals designated by the local emergency response agency.
 - (2) After approval of a Form 9, Transfer of Operatorship pursuant to Rule 218.e, the Buying Operator will coordinate with the local emergency response agency to update the emergency response plan as appropriate.
- k. Vehicles not necessary for drilling, production, servicing, or seismic operations will be located a minimum distance of 100 feet from the wellbore, or a distance equal to the height of the derrick or mast, whichever is greater. Operators will take equivalent safety measures where terrain, location, or other conditions do not permit this minimum distance.
 - l. Existing Production Facilities are exempt from the provisions of the Commission's Rules with respect to minimum distance requirements and setbacks unless they are found by the Director to be unsafe.
 - m. Operators will provide self-contained physically secured sanitary facilities during drilling operations and at any other similarly staffed Oil and Gas Location or Oil and Gas Facility, and ensure that waste remains contained within the sanitary facilities.

603. OPERATIONAL AND SAFETY REQUIREMENTS

- a. **Blowout Prevention Equipment ("BOPE").** The Operator will take all necessary precautions for keeping a Well under control during drilling, deepening, re-entering, recompleting, workovers, or plugging. The Operator will indicate the BOPE, if any, on the Form 2, Application for Permit to Drill, as well as any known subsurface conditions (e.g., under- or over-pressured formations). The Operator will ensure the working pressure of any BOPE exceeds the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 pounds per square inch ("psi") per foot.
 - (1) The Commission may designate specific areas, Fields, or formations as requiring certain BOPE. Any such proposed designation will occur by notice describing the area, Field, or formation in question and will be given to all Operators of record within such area or Field and by publication. The proposed designation, if no protest is timely filed, will be placed on the Commission consent agenda for its next regularly scheduled meeting. The matter will be approved or heard by the Commission pursuant to Rule 519. Such designation will be effective immediately upon approval by the Commission, except as to any previously approved Form 2. If a protest is timely filed, the designation will be heard by the Commission pursuant to the Commission's 500 Series Rules.
 - (2) Pursuant to this Rule 603.a, the Director may condition the approval of any Form 2 by requiring BOPE which the Director determines to be necessary for keeping the Well under control. Should the Operator object to such condition of approval, the Commission will hear the matter at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 504.
- b. **Rig Floor Safety Valve Requirements.** During drilling or Well servicing operations there will be on the rig floor a safety valve with connections suitable for use with each size and type of tool joint or coupling being used on the job.
- c. **Well Servicing Operations.**
 - (1) **Pressure Check Requirements.** Prior to commencing Well servicing operations, the Well

will be checked for pressure and steps taken to remove pressure or to ensure that operations may be safely conducted under pressure.

(2) BOPE.

- A.** Adequate BOPE equipment will be used on all Well servicing operations.
- B.** Backup stabbing valves will be required on Well servicing operations during reverse circulation. Valves will be pressure tested before each Well servicing operation using low-pressure air or Fluid or high-pressure Fluid.

(3) All Well servicing operations will be conducted in accordance with American Petroleum Institute ("API") Recommended Practice ("RP") 54, Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations, Third Edition Reaffirmed, January 2013. Only the Third Edition of API's RP 54 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

(4) An Operator will:

- A.** Design drilling Fluid in conjunction with operating procedures and surface equipment to prevent the blowout of any Well until the Well has been placed into production;
- B.** Maintain adequate supplies of drilling Fluid of sufficient weight and other acceptable characteristics;
- C.** Perform drilling Fluid tests as necessary to ensure Well control;
- D.** Maintain adequate drilling Fluid testing equipment on the location at all times;
- E.** Monitor wellbore Fluid levels to ensure Well control at all times, including when running or pulling pipe;
- F.** Monitor mud Pit levels visually or mechanically during the drilling process; and
- G.** Install and operate mud-gas separation equipment as necessary.

(5) The Director will have access to the drilling Fluid records related to the Fluid's properties used to control the Well (Fluid type, density, viscosity, Fluid loss control, and other rheological properties), and will be allowed to request or conduct any essential tests on the drilling Fluid used in the drilling or recompletion of a Well. The Operator will retain all records for a period of 5 years.

(6) When the conditions and tests indicate a need for a change in the drilling Fluid program in order to ensure control of the Well, the Operator will use due diligence in modifying the program.

(7) An Operator will maintain Well control using BOPE systems and/or diverter systems for Wells drilled with air, nitrogen, or foam.

(8) The Operator will install BOPE when there is any indication that a Well will flow, either through prior records, present Well conditions, or the planned Well work, or special orders of the Commission.

- (9) When required, BOPE will be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018). Only the 5th Edition of API Standard 53 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.
- (10) Drilling after setting the surface casing will not proceed until BOPE is tested and found to be serviceable. Low pressure and high pressure tests will be performed. Test pressure, test duration, and test frequency will be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018), as incorporated by reference in Rule 603.c.(9), except that the minimum low pressure for a low pressure test will be 250 psi. Test pressure loss will be less than or equal to 10% of the initial stabilized surface pressure at the end of the test when testing with rig pumps against casing. When a test plug is used to isolate the casing from the BOPE being tested, then there will be no unexplainable pressure loss at the end of the test.
- (11) While in service, BOPE will be inspected daily and a preventer operating test will be performed on each round trip, but not more than once every 24 hour period. Notation of operating tests will be made on the daily report.
- (12) All pipe fittings, valves, and unions placed on or connected with BOPE, well casing, wellhead, drill pipe, or tubing will have a working pressure rating suitable for the maximum anticipated surface pressure and will be in good working condition as per generally accepted industry standards. The Operator will equip wellhead assemblies to monitor pressure-containing annuli at surface, unless exempted by the Director.
- (13) BOPE will include pipe rams, blind rams, annular preventer, or other equipment that enable closure on the pipe being used. The choke line(s) and kill line(s) will be anchored, tied, or otherwise secured to prevent whipping resulting from pressure surges.
- (14) The Operator will inspect and service the wellhead, tree, and related surface control equipment to maintain pressure control throughout the life of the Well.
- (15) The Operator will conduct pressure testing of the casing string pursuant to Rule 408.
- (16) An Operator will complete a formation integrity test ("FIT") after drilling out below the surface casing shoe and any intermediate casing shoes for a minimum of 1 Well on each Oil and Gas Location if:
- A. The fracture gradient of the formation at the casing shoe is unknown; or
 - B. The test is necessary to demonstrate:
 - i. The casing shoe integrity is sufficient to contain the anticipated wellbore pressures of the penetrated formations;
 - ii. Flow paths to the formations above the casing shoe do not exist; or
 - iii. The casing shoe is competent to handle an influx of formation Fluid or gas.
 - C. An Operator will submit a plan to the Director for approval if the FIT does not demonstrate the requirements of Rule 603.c.(16).B.

- D. The Operator will perform the FIT before drilling 20 feet or less of new hole, unless otherwise ordered by the Commission.
- (17) If the blind rams are closed for any purpose except operational testing, the valves on the choke lines or relief lines below the blind rams should be opened prior to opening the rams to bleed off any pressure.
- (18) BOPE for drilling operations will consist of (at a minimum):
- A. **Rig with Kelly.** Double ram with blind ram and pipe ram; annular preventer or a rotating head.
 - B. **Rig Without Kelly.** Double ram with blind ram and pipe ram.
 - C. **Trained Personnel.**
 - i. During drilling operations there will be at least 2 persons at the Well Site that have successfully completed an International Association of Drilling Contractors certified Well control training, or have completed a Director-approved BOPE training.
 - ii. All rig employees will have adequate understanding of and be able to operate the BOPE system. New employees will be trained in the operation of BOPE systems.
- (19) **BOPE Testing for Drilling Operations.** Upon initial rig-up and at least once every 30 days during drilling operations thereafter, pressure testing of the casing string and each component of the BOPE including flange connections will be performed to 70% of working pressure or 70% of the internal yield of casing, whichever is less. Pressure testing will be conducted and the documented results will be retained by the Operator for inspection by the Director for a period of 1 year. Activation of the pipe rams for function testing will be conducted on a daily basis when practicable.
- d. **Well Consolidation.** Where necessary and reasonable, Operators will consolidate new Wells to create multi-Well pads, including shared locations with other Operators to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.
 - e. **Development from Existing Oil and Gas Locations.** Where possible, Operators will develop multiple reservoirs by drilling from existing Oil and Gas Locations or by multiple completions or commingling in existing wellbores.
 - f. **Pit Level Indicators.** Pit level indicators will be used for mud Tanks and Drilling Pits.
 - g. **Drill Stem Tests.** Closed chamber drill stem tests will be allowed. All other drill stem tests require Director approval.
 - h. **Fencing Requirements.** Unless otherwise requested by the Surface Owner, Oil and Gas Locations or Oil and Gas Facilities will be adequately fenced to restrict access by unauthorized persons, if determined necessary by the Director. However, all pumps and Pits will be adequately fenced to prevent access by unauthorized persons.
 - i. **Loadlines.** All loadlines will be bullplugged or capped.
 - j. **Guy Line Anchors.** All guy line anchors left buried for future use will be identified by a marker of bright color not less than 4 feet in height and not greater than 1 foot east of the guy line anchor.

- k. Tank Specifications.** All newly installed or replaced crude oil and condensate storage Tanks will be designed, constructed, and maintained pursuant to the National Fire Protection Association (“NFPA”) Code 30, Flammable and Combustible Liquids Code (2018 version). The Operator will maintain written records verifying proper design, construction, and maintenance, and will make these records available for inspection by the Director. Only the 2018 version of NFPA Code 30 applies to this Rule; later amendments do not apply. All materials incorporated by reference in this Rule are available for public inspections during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.
- l. Access Roads.** At the time of construction, all leasehold roads will be constructed to accommodate all weather access by local emergency vehicles, and will be maintained in a stable condition.
- m. Well Site Cleared.** Within 90 days after a Well is Plugged and Abandoned, the Well Site will be cleared of all non-essential equipment, trash, and debris. For good cause shown, a reasonable extension of time may be granted by the Director. The Operator will request prior approval for this extension on a Form 4, Sundry Notice.
- n. Identification of Plugged and Abandoned Wells.** The Operator will identify the location of the wellbore with a permanent monument pursuant to Rule 434.a.(5).
- o. Secondary Containment.** Operators will design, construct, and maintain secondary containment devices around new and significantly modified crude oil, condensate, and produced water storage Tanks.
- (1) Operators will design secondary containment structures to be sufficiently sized to contain at least 150% of the volume of the largest single Tank within the containment.
 - (2) Operators will construct secondary containment of steel, or other engineered material, designed and installed to prevent leakage and resist degradation from erosion or routine operation.
 - (3) To prevent leakage, Operators will line secondary containment areas with an impervious synthetic or engineered liner that underlays all primary containment vessels including partially buried vessels. The liner will be sufficiently impervious so that any discharge from a primary containment system will not escape containment before cleanup occurs. The liner will be attached to secondary containment and any equipment penetrating the liner will have a sealed connection.
 - (4) Secondary containment will prevent Spills or Releases from primary containment vessels, process vessels, or pipelines from migrating horizontally or vertically prior to clean-up.
 - (5) For locations within 500 feet and upgradient of a surface water body or wetland, tertiary containment, such as a compacted earthen berm, is required around Production Facilities.
 - (6) No potential ignition sources, aside from fired vessels (“FV”), will be installed inside the secondary containment area. Any electrical equipment installations inside the bermed area will comply with API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities classified as Class I, Division I and Division 2, 3rd Edition (including January 2014 errata), and the current national electrical code as adopted by the State of Colorado. Only the 3rd edition (including January 2014 errata) of API RP 500 applies to this Rule; later amendments do not apply. The 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, CO 80203. In addition, these materials are available from API, 1220 L Street NW, Washington, DC 20005-4070, and from the Department of Regulatory Agencies, Colorado Electrical Board, 1560 Broadway, Suite 110, Denver, CO 80202.

604. SETBACKS and SITING REQUIREMENTS

a. Well Location Requirements.

- (1) At the time the Well is drilled, a Well will be located not less than 200 feet from buildings, public roads, above ground utility lines, or railroads.
- (2) At the time a Form 2A, Oil and Gas Location Assessment is filed, a Well will be located not less than 150 feet from a surface property line. The Commission may grant an exception if it is not feasible for the Operator to meet this minimum distance requirement and a waiver is obtained from the offset Surface Owner(s). The Operator will submit an exception location request letter stating the reasons for the exception and a signed waiver(s) from the offset Surface Owner(s) with the Form 2A for the proposed Oil and Gas Location where the Well will be drilled. Such signed waiver will be filed in the office of the county clerk and recorder of the county where the Well will be located.
- (3) No Working Pad Surface will be located 2,000 feet or less from a School Facility or Child Care Center.
 - A. If the Operator and School Governing Body disagree as to whether a proposed Working Pad Surface is 2,000 feet or less from a School Facility or Child Care Center, the Commission will hear the matter in the course of considering the proposed Oil and Gas Development Plan. At the hearing, the Operator will demonstrate that the Working Pad Surface is more than 2,000 feet from any School Facility or Child Care Center.
 - B. Any hearing required under Rule 604.b.(3).A will be held at a location reasonably proximate to the lands affected by the proposed Oil and Gas Development Plan.
- (4) No Working Pad Surface will be located less than 500 feet from 1 or more Residential Building Units not subject to a Surface Use Agreement or waiver, that includes informed consent from all Building Unit owner(s) and tenant(s) explicitly agreeing to the proposed Oil and Gas Location siting.

b. Siting Requirements for Proposed Oil and Gas Locations Near Residential Building Units and High Occupancy Building Units. No Working Pad Surface will be located more than 500 feet and less than 2,000 feet from 1 or more Residential Building Units or High Occupancy Building Units unless one or more of the following conditions are satisfied:

- (1) The Residential Building Unit owners and tenants and High Occupancy Building Unit owners and tenants within 2,000 feet of the Working Pad Surface explicitly agree with informed consent to the proposed Oil and Gas Location;
- (2) The location is within an approved Comprehensive Area Plan that includes preliminary siting approval pursuant to Rule 314.b.(5) or an approved Comprehensive Drilling Plan;
- (3) Any Wells, Tanks, separation equipment, or compressors proposed on the Oil and Gas Location will be located more than 2,000 feet from all Residential Building Units or High Occupancy Building Units; or

- (4) The Commission finds, after a hearing pursuant to Rule 510, that the proposed Oil and Gas Location and conditions of approval will provide substantially equivalent protections for public health, safety, welfare, the environment, and wildlife resources, including Disproportionately Impacted Communities. The Commission will base its finding on information including but not limited to:
- A. The Director's Recommendation on the Oil and Gas Location pursuant to Rule 306.b;
 - B. The extent to which the Oil and Gas Location design and any planned Best Management Practices, preferred control technologies, and conditions of approval avoid, minimize, and mitigate adverse impacts, considering:
 - i. Geology, technology, and topography;
 - ii. The location of receptors and proximity to those receptors; and
 - iii. The anticipated size, duration, and intensity of all phases of the proposed Oil and Gas Operations at the proposed Oil and Gas Location.
 - C. The Relevant Local Government's consideration or disposition of a land use permit for the location, including any siting decisions and conditions of approval identified as appropriate by the Relevant Local Government;
 - D. The Operator's alternative location analysis conducted pursuant to Rule 304.b.(2), or an alternative location analysis performed for the Relevant Local Government that the Director has accepted as substantially equivalent pursuant to Rule 304.e;
 - E. Related Oil and Gas Location siting and infrastructure proposed as a component of the same Oil and Gas Development Plan as the proposed Oil and Gas Location;
 - F. How Oil and Gas Facilities associated with the proposed Oil and Gas Location are designed to avoid, minimize, and mitigate impacts on Residential Building Units and High Occupancy Building Units; or
 - G. The Operator's actual and planned engagement with nearby residents and businesses to consult with them about the planned Oil and Gas Operations.

605. SIGNAGE REQUIREMENTS FOR OIL AND GAS OPERATIONS

- a. **Oil and Gas Location Signage.** For new Oil and Gas Locations, from the time of construction until Reclamation is complete, the Operator will post a sign at the entrance to an Oil and Gas Location that includes the:
- (1) Oil and Gas Location name;
 - (2) Commission's assigned Oil and Gas Location identification number (ID #);
 - (3) The Operator's telephone number where it may be reached at all times; and
 - (4) Telephone number(s) for local emergency services (911 where available).

b. Road Signage Requirements During Drilling Operations.

- (1) Concurrent with or prior to Move-In, Rig-Up (“MIRU”), the Operator or its contractor will place a sign or marker at the point of intersection of the public road and rig access road, and the sign will be maintained until the drill rig is released.
- (2) The sign placed during drilling operations will identify the public road to be used in accessing the rig, along with all necessary emergency numbers, and will be posted in a conspicuous place at the drilling rig.

c. Drilling, Hydraulic Fracturing Treatment, Flowback, and Recompletion Operations.

- (1) Directional signs, no less than 3 square feet and no more than 6 square feet in size, will be provided during drilling, Hydraulic Fracturing Treatment, Flowback, and recompletion operations by the Operator or contractor.
- (2) Such signs will be at locations sufficient to advise emergency crews where drilling, Hydraulic Fracturing Treatment, Flowback, and recompletion operations are taking place. At a minimum, such locations will include:
 - A. The first point of intersection of a public road and the rig access road; and
 - B. Thereafter at each intersection of the rig access route, except where the route to the Oil and Gas Location is clearly obvious to uninformed third parties.
- (3) Signs not necessary to meet other obligations under the Commission’s Rules will be removed as soon as practicable after the operation is complete.

d. Well Signage Requirements.

- (1) Within 60 days after a new Well is Completed, including each Well on a Multi-Well Site, or an existing sign is replaced or modified, a permanent sign will be conspicuously located at the wellhead and will identify:
 - A. The Well name;
 - B. The API number; and
 - C. Its legal location, including the quarter/quarter section.
- (2) When no associated Tank battery is present at the Oil and Gas Location, the following additional information is required on the Well sign:
 - A. Name of the Operator;
 - B. Telephone number at which the Operator can be reached at all times;
 - C. Telephone number for local emergency services (911 where available); and
 - D. The public road used to access the Well.
- (3) **Multi-Well Locations.** On a multi-Well location the information required by Rule 605.d.(2) may be placed on one sign with dimensions as described in Rule 605.e.(2).
- (4) If a Well is a known source of hydrogen sulfide gas, it will be marked accordingly.

e. Tank Battery Signage.

- (1) Within 60 days after the installation of a Tank battery, a permanent, conspicuous sign will be located at the battery.
- (2) The Tank battery sign will be no less than 3 square feet and no more than 6 square feet, and will provide:
 - A. Name of the Operator;
 - B. Telephone number at which the Operator can be reached at all times;
 - C. Telephone number for local emergency services (911 where available);
 - D. The public road used to access the Tank battery site;
 - E. Well name(s) and API number(s) associated with the Tank battery and the legal location of the Well(s); and
 - F. Location, including the quarter/quarter section, of the Tank battery.
- (3) If an Oil and Gas Location is a known source of hydrogen sulfide gas, it will be marked accordingly.

f. Centralized E&P Waste Management Facility Signage.

- (1) The main point of access to a Centralized E&P Waste Management Facility will be marked by a sign captioned:

“(Operator name) E&P Waste Management Facility, Permit #.”

Such sign will be no less than 3 square feet and no more than 6 square feet and will provide:
 - A. A phone number at which the Operator can be reached at all times;
 - B. A phone number for local emergency services (911 where available);
 - C. The public road used to access the facility; and
 - D. The legal location, including quarter/quarter section, of the facility.
- (2) If a Centralized E&P Waste Management Facility is a known source of hydrogen sulfide gas, it will be marked accordingly.

g. General Sign Requirements.

- (1) No sign required under this Rule 605 will be installed at a height exceeding 6 feet.
- (2) Operators will ensure that signs are well maintained and legible, and will replace damaged or vandalized signs within 30 days of discovery that the sign is no longer legible or is damaged.
- (3) Upon the Director’s approval of a Form 9 the Buying Operator will have 60 days to replace or update all signs at the Oil and Gas Location so that the signs comply with Rule 605.

h. Tank and Container labels.

- (1) All Tanks with a capacity of 10 Barrels or greater will be labeled or posted with the following information:
 - A. Name of Operator;
 - B. Operator's emergency contact telephone number;
 - C. Tank capacity;
 - D. Tank contents; and
 - E. NFPA label or equivalent globally harmonized label.
- (2) Lettering on all new Tanks, and on any reapplied or modified labels, will be legible from a distance of 100 feet.
- (3) Containers that are used to store, treat, or otherwise handle a hazardous material and which are required to be marked, placarded, or labeled in accordance with the U.S. Department of Transportation's Hazardous Materials Regulations, will retain the markings, placards, and labels on the Container. Such markings, placards, and labels will be retained on the Container until it is sufficiently cleaned of residue and purged of vapors to remove any potential hazards.

606. EQUIPMENT, WEEDS, WASTE, AND TRASH REQUIREMENTS.

- a. The storage, placement, or maintenance of equipment, vehicles, trailers, commercial products, Chemicals, drums, totes, Containers, materials, and all other supplies not necessary for use on an Oil and Gas Locations is prohibited.
 - (1) This prohibition applies to the Operator and all contractors.
 - (2) An Operator may request a variance pursuant to Rule 502 for a Surface Owner to use portions of the Oil and Gas Location, provided such use does not interfere with safe operations, access to equipment, Reclamation requirements, or emergency response capabilities. Such use cannot cause degradation to the site.
 - (3) This prohibition does not apply to emergency response trailers and associated equipment staged on an Oil and Gas Location for emergency response purposes.
- b. No maintenance of equipment or vehicles is permitted at an Oil and Gas Location unless immediately necessary to allow for the continuation of active Oil and Gas Operations.
- c. Oil and Gas Locations will be kept free of all Undesirable Plant Species.
- d. **Trash.**
 - (1) Operators will properly dispose of all trash, rubbish, and other waste materials as non-hazardous/non-E&P solid waste, pursuant to Rule 906.c.
 - (2) No trash, waste, rubbish, or other materials will be burned or buried at an Oil and Gas Location.

- (3) All trash, rubbish, and other waste material will be properly contained until removed from the Oil and Gas Location. At no time will trash, debris, or rubbish be placed or remain on the ground.
 - A. Appropriate Containers are Containers that prevent leakage of Fluids, and are capable of containing waste materials in all weather conditions.
 - B. Appropriate Containers will be designed, maintained, and operated to exclude wildlife.

607. EQUIPMENT ANCHORING REQUIREMENTS

All equipment at an Oil and Gas Location in a Geologic Hazard area will be anchored. Anchors will be engineered to support the equipment and to resist flotation, collapse, lateral movement, or subsidence. Anchoring requirements in Floodplains are governed by Rule 421.b.(2).

608. OIL AND GAS FACILITIES

a. Production Liquid Storage Tanks.

- (1) Atmospheric Tanks used for produced Fluids storage will be built in accordance with the following standards as applicable. Only those editions of standards incorporated by reference in Rules 608.a.(1).A–F apply; later amendments do not apply. All materials incorporated by reference in this Rule 608.a.(1) 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070, and from Underwriters Laboratories, Inc., 100 Technology Drive, Broomfield, CO 80021.
 - A. Underwriters Laboratories, Inc., No. UL-142, Standard for Steel Above Ground Tanks for Flammable and Combustible Liquids, 10th Edition (May 17, 2019);
 - B. API Standard No. 650, Welded Steel Tanks for Oil Storage, 13th Edition (March 2020);
 - C. API Standard No. 12B, Bolted Tanks for Storage of Production Liquids, 16th Edition (November 2014);
 - D. API Standard No. 12D, Field Welded Tanks for Storage of Production Liquids, 12th Edition (June 2017);
 - E. API Standard No. 12F, Shop Welded Tanks for Storage of Production Liquids, 13th Edition (January 2019); or
 - F. API Standard No. 12P, Specification for Fiberglass Reinforced Plastic Tanks, 4th edition (August 2016), only for produced water.
- (2) Tanks used for produced Fluids storage will be located at least 2 diameters from the boundary of the property on which the Tank is built. Where the property line is a public right of way, the Tanks will be 2/3 of the diameter from the nearest side of the public right of way or easement.
 - A. Tanks with less than 3,000 Barrels capacity will be located at least 3 feet apart.
 - B. Tanks with 3,000 or more Barrel capacity will be located at least 1/6 the sum of the diameters apart. When the diameter of one Tank is less than 1/2 the diameter of the

adjacent Tank, the Tanks will be located at least 1/2 the diameter of the smaller Tank apart.

- (3) All production Tanks greater than 60 gallons will conform to minimum standards of NFPA Code 30, 2018 Edition unless otherwise specified. Only the 2018 version of NFPA Code 30 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, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.
- (4) At the time of installation, Tanks will be a minimum of 200 feet from any building.
- (5) Unless equipped with a fired heater, Tanks will be a minimum of 75 feet from a FV or heater-treater ("HT"). No ancillary equipment that has potential ignition sources will be installed or used inside the secondary containment area.
- (6) Tanks will be a minimum of 50 feet from a separator, Well test unit, or other non-fired equipment. Non-fired vapor recovery towers, transfer pumps, vapor line knockouts, and LACT units are exempt from this requirement.
- (7) Tanks will be a minimum of 75 feet from a compressor with a rating of greater than or equal to 200 horsepower.
- (8) Tanks will be a minimum of 75 feet from a wellhead.
- (9) Gauge hatches on atmospheric Tanks used for crude oil storage will be closed, latched, and sealed at all times when not being actively accessed by trained personnel. Tanks will function as sealed and ventless with gas released only through a vapor control system or properly sized pressure relief valve.
- (10) **Tank Venting Standards.**
 - A. All Tank Venting systems will be designed, constructed, and operated in accordance with API Standard 2000, Venting Atmospheric and Low Pressure Storage Tanks, 7th edition, March 2014. Only the 7th Edition of the API standard 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, CO 80203. In addition, these materials are available from API at 1220 L Street, NW Washington, DC 20005-4070.
 - B. Except for individual blowdown lines used to depressurize Tanks prior to opening gauge hatches, vent lines from individual Tanks will be joined and ultimate discharge will be directed away from the loading racks and FV pursuant to API RP 12R-1, Installation, Operation, Maintenance, Inspection, and Repair of Tanks in Production Service, 6th Edition, March 2020. Only the 6th Edition of API RP 12R-1 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.
 - C. During drilling, completion, production, and storage operations, all sealed Tanks will be designed for a minimum of 4 ounces of backpressure. Vent/back pressure valves, the

combustor, lines to the combustor, and knock-outs will be sized and maintained so as to safely accommodate any surge the system may encounter. Operators will properly maintain, and periodically test, Tank seals to ensure that they provide the required back pressure and prevent emissions.

- (11) During hot oil treatments on Tanks containing 35 degrees or higher API gravity oil, hot oil units will be located a minimum of 100 feet from any Tank being serviced.
- (12) **Labeling of Tanks.** All Tanks and Containers will be labeled pursuant to Rule 605.h.
- (13) All open-topped Tanks will be equipped with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.
- (14) **Change in Service.** Tanks undergoing change in service will be emptied, cleaned, and re-labeled for the new use (if any). Operators will manage all waste generated during change in service pursuant to Rule 906.

b. Fired Vessel, Heater-Treater, and Separation Equipment.

- (1) Fired vessels ("FV") including heater-treaters ("HT") will be minimum of 50 feet from separators or Well test units.
- (2) FV-HT will be a minimum of 50 feet from a lease automatic custody transfer unit ("LACT").
- (3) FV-HT will be a minimum of 40 feet from a pump.
- (4) FV-HT will be a minimum of 75 feet from a Well.
- (5) At the time of installation, FV-HT will be a minimum of 200 feet from a Residential Building Unit.
- (6) Vents on pressure safety devices will terminate in a manner so as not to endanger the public or adjoining facilities. They will be designed to be clear and free of debris and water at all times.
- (7) All stacks, vents, or other openings will be equipped with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.
- (8) All separation equipment will be designed, constructed and maintained according to API Spec 12J, Specification for Oil and Gas Separators, 8th edition, October 2008. Only the 8th Edition (2008) of API Spec 12J 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, CO 80203. In addition, these materials and are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

c. Special Equipment. The Director may require an Operator to employ special equipment to protect public safety.

- (1) All Wells located within 500 feet of a Residential Building Unit will be equipped with an automatic isolation valve that will shut the Well in when a sudden change of pressure, either a rise or drop, occurs. Automatic isolation valves will be designed so they are fail safe.

- (2) Isolation valves required by Rule 608.c.(1) will be electronic or activated by a secondary gas source supply, and will be inspected at least every 3 months to ensure the valves are in good working order and that the secondary gas supply has volume and pressure sufficient to activate the isolation valve.

d. Static Charge, Lightning, and Stray Current Requirements. All equipment will be designed and operated in a manner to prevent accumulation of static charge pursuant to API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents, 8th Edition, September 2015. Only the 8th Edition (2015) of API RP 2003 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

e. Mechanical Conditions. All Production Facilities, valves, pipes, fittings, and vessels will be securely fastened or sealed, inspected at regular intervals, and maintained in good mechanical condition. All equipment will be engineered, operated, and maintained within the manufacturer's recommended specifications.

f. Buried or Partially Buried Tanks, Vessels, or Structures.

- (1) Buried or partially buried Tanks, vessels, or structures used for storage of produced Fluids and E&P Waste will be properly designed, constructed, installed, and operated in a manner to prevent leaks, contain materials safely, and according to manufacturer specifications.

- (2) Buried or partially buried Tanks, vessels, or structures will be underlain by an impermeable synthetic or engineered liner that extends to the surface and ties into the secondary containment. In lieu of an impermeable liner, double walled Tanks may be used to meet the requirements of this Rule 608.f.(2).

- (3) Operators will inspect or test buried or partially buried Tanks, vessels, or structures for leaks at least annually. Operators will maintain records documenting tests conducted pursuant to this Rule 608.f.(3) for 5 years, and provide the records to the Director upon request.

- (4) If any leaks are detected, Operators will repair or replace the Tank, vessel, or structure to prevent future Spills or Releases of E&P Waste. Operators will report, investigate, and remediate any Spill or Release pursuant to Rules 912 & 913.

g. Fluid Handling Equipment. Any piece of Fluid handling equipment that is not a Tank or Flowline, including temporary equipment, and regardless of the volume the equipment is designed to hold, will have either general secondary containment around the equipment, or a written Spill contingency plan. The written Spill contingency plan will include at least the following standards:

- (1) A written commitment of manpower, equipment, and materials required to expeditiously control and contain all discharged Fluids;

- (2) A schedule and protocol for periodic visual inspection or testing flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge;

- (3) Procedures for taking corrective action or making repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge; and

- (4) Procedures for prompt removal, Remediation, and reporting, if required, for any accumulations of discharges.

609. INSPECTIONS

- a. Unless otherwise specified by the Commission's Rules, Operators will inspect Oil and Gas Locations as set forth below. Operators will promptly investigate, and if appropriate, repair, replace, or remediate any malfunctioning equipment or process. If an Operator takes action to address any malfunctioning equipment or process identified during an inspection, the Operator will maintain documentation of the action taken, and provide it to the Director upon request. The Operator will submit documentation of the results of all Tank system inspections to the Director upon request.
- b. **Tank and Process Vessel Inspections.** All in-service Tanks and process vessels will be inspected and maintained pursuant to one of the following applicable standards:
 - (1) For Tanks that are built to meet API Standard 650, as incorporated by reference in Rule 608.a.(1).B, or are greater than 30 feet in diameter, API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, (Fifth Edition, Including Addendum 1 (2018), Addendum 2 (2020), and Errata 1 (2020)). Only the fifth edition (2018, including 2020 Addendum 2 and Errata 1) of API Standard 653 apply; 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.
 - (2) For all other Tanks, either:
 - A. API Standard 12R1, Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service (6th edition March 2020). Only the 6th edition (March 2020) of API Standard 12R1 applies; 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070; or
 - B. Steel Tank Institute ("STI") SP001, Standard for the Inspection of Aboveground Storage Tanks (January 2018). Only the January 2018 version of STI SP001 applies; 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, CO 80203. In addition, these materials are available from STI, 944 Donata Court, Lake Zurich, IL 60047.
 - (3) For process vessels, API Standard 510, Pressure Vessel Inspector (10th edition May 2014). Only the 10th Edition (May 2014) of API Standard 510 applies to this Rule; later amendments do not apply. API Standard 510 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, CO 80203. In addition, these materials may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070.
- c. **Out of Service Tanks and Process Vessels.** Out of service Tanks and process vessels are not subject to the inspection standards in Rule 609.b. Operators will:

- (1) Isolate or disconnect the Tank or process vessel from sources of oil, condensate, produced water, or natural gas;
 - (2) Depressurize and evacuate all hydrocarbons and produced water from the Tank or process vessel and test the interior of the Tank or process vessel to show that it is safe for designated entry, cleaning, or repair work.;
 - (3) Apply OOSLAT; and
 - (4) Equip any openings in the Tank or process vessel with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.
- d. Audio Visual Olfactory Inspections.** Operators will conduct Audio, Visual, Olfactory (“AVO”) inspections of all Oil and Gas Facilities, at the same inspection frequency required by the Air Quality Control Commission Regulation 7, 5 C.C.R. §§ 1001-9:D.I.E.2.c.viii–ix & 1001-9:D:II.C.1.d (2021) (“AQCC Regulation 7”). Only the version of the AQCC Regulation 7 in effect as of January 15, 2021 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, CO 80203. In addition, AQCC Regulation 7 is available from the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at <https://www.colorado.gov/pacific/cdphe/aqcc-regs>. When performing an AVO inspection, an Operator will survey the Oil and Gas Facility using audio, visual, and olfactory techniques to detect failures, leaks, Spills, or Releases, or signs of a leak, Spill, or Release.

610. FIRE PREVENTION AND PROTECTION

- a. Gasoline-fueled engines will be shut down during fueling operations.
- b. Operators will comply with all Division of Oil and Public Safety regulations during handling, connecting, and transfer operations involving liquefied petroleum gas (“LPG”), 7 C.C.R. § 1101-15, *et seq.* Only the version of the Division of Oil and Public Safety’s LPG Regulations, 7 C.C.R. § 1101-15, *et seq.* in effect as of January 15, 2021 apply to this Rule; later versions 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, CO 80203. In addition, these materials are from the Division of Oil and Public Safety, 633 17th St., Suite 500, Denver, CO 80202, and are available online at <https://www.colorado.gov/pacific/ops/RegulationsStatutes>.
- c. Flammable liquids storage areas within any building or shed will:
 - (1) Be adequately vented to the outside air;
 - (2) Have 2 unobstructed exits leading from the building in different directions if the building is in excess of 500 square feet;
 - (3) Be maintained with due regard to fire potential with respect to housekeeping and materials storage; and
 - (4) Be identified as a hazard and appropriate warning signs posted.
- d. Flammable liquids will not be stored within 50 feet of the wellbore, except for the fuel in the tanks of operating equipment or supply for injection pumps.

- e. LPG Tanks larger than 250 gallons and used for heating purposes will be placed as far as practicable from and parallel to the adjacent side of the rig or wellbore as terrain and location configuration permit. Installation will be consistent with provisions of NFPA Code 58, Liquid Petroleum Gas Code (2020 edition). Only the 2020 edition of NFPA Code 58 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, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.
- f. Smoking is prohibited within 150 feet of the wellbore, on any drilling or workover site, at an Oil and Gas Location with a producing Well or a Well that is undergoing Hydraulic Fracturing Treatment or Flowback, or in the vicinity of operations which constitute a fire hazard. Such locations will be conspicuously posted with a sign, "No Smoking or Open Flame."
- g. No matches, smoking equipment, or source of ignition will be carried into "No Smoking or Open Flame" areas.
- h. Open fires, transformers, or other sources of ignition will be permitted only in designated areas located at a safe distance from the wellhead or flammable liquid storage areas or areas with potential for ignition of gas or vapors.
- i. Only approved heaters for Class I Division 2 areas, as designated by API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2, 3rd Edition (including January 2014 errata), will be permitted on an Oil and Gas Location or near Oil and Gas Facilities. The safety features of these heaters will not be altered. Only the 3rd edition, including January 2014 errata, of API RP 500 applies to this Rule; later editions 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.
- j. Combustible materials such as oily rags and waste will be stored in covered metal Containers.
- k. **Control of Fire Hazards.** Any material not in use that might constitute a fire hazard will be removed a minimum of 25 feet from the wellhead(s), Tanks, and separator(s). Any electrical equipment installations inside the secondary containment areas will comply with API RP 500 classifications and comply with the current national electrical code as adopted by the State of Colorado. Only the 3rd edition (including January 2014 errata) of API RP 500 applies to this Rule; later amendments do not apply. API RP 500 and Colorado's current national electrical code 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, CO 80203. In addition, these materials are available from API, 1220 L Street NW, Washington, DC 20005-4070, and from the Department of Regulatory Agencies, Colorado Electrical Board at 1560 Broadway, Suite 110, Denver, CO 80202.
- l. Material used for cleaning will have a flash point of not less than 100 degrees Fahrenheit. For limited special purposes, a lower flash point cleaner may be used when it is specifically required and will be handled with extreme care.
- m. Firefighting equipment will not be tampered with and will not be removed other than for fire protection and firefighting purposes and services. A firefighting water system may be used for wash down and other utility purposes so long as its firefighting capability is not compromised. After use, water systems will be properly drained or properly protected from freezing.

- n. An adequate amount of fire extinguishers and other firefighting equipment will be suitably located, readily accessible, and plainly labeled as to their type and method of operation.
- o. Fire protection equipment will be periodically inspected, and maintained in good operating condition at all times.
- p. Firefighting equipment will be readily available near all welding operations. When welding, cutting, or other hot work is performed a person will be designated as a fire watch. The area surrounding the work will be inspected at least 1 hour after the hot work is completed.
- q. Portable fire extinguishers will be tagged showing the date of last inspection, maintenance, or recharge. Inspection and maintenance procedures will comply with NFPA Code 10, Standards for Portable Fire Extinguishers (2018). Only the 2018 Edition of NFPA Code 10 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, CO 80203. In addition, these materials are available from NFPA, 1 Batterymarch Park, Quincy, MA, 02169.
- r. All employees, contractors, and subcontractors will be shown the location of fire control equipment including, but not limited to Fluid guns, water hoses, and fire extinguishers, and trained in the use of such equipment. They will also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit.

611. AIR AND GAS DRILLING

- a. Drilling compressors (air or gas) will be located at least 125 feet from the wellbore and in a direction away from the air or gas discharge line.
- b. The air or gas discharge line will be laid in as nearly a straight line as possible from the wellbore and be a minimum of 150 feet in length. The line will be securely anchored.
- c. A pilot flame will be maintained at the end of the air or gas discharge line at all times when air, gas, or mist drilling, or Well testing is in progress.
- d. All combustible material will be kept at least 100 feet away from the air and gas discharge line and Flare Pit.
- e. The air line from the compressors to the standpipe will be of adequate strength to withstand at least the maximum discharge pressure of the compressors used, and will be checked daily for any evidence of damage or weakness.

612. HYDROGEN SULFIDE GAS

a. General.

- (1) Operators will avoid any uncontrolled release or hazardous accumulation of hydrogen sulfide ("H₂S") gas. If releases or hazardous accumulations of H₂S cannot be avoided, or during upset conditions or malfunctions, Operators will employ mitigation measures to reduce potential harms to safety.
- (2) **Scope.** To protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, Operators will comply with this Rule 612 where oil and gas exploration and production occurs in areas known or reasonably expected to contain H₂S.

b. Radius of Exposure Calculation. When an Operator is conducting drilling, workover, completion, or production operations in a geologic zone where the Operator knows or reasonably expects to encounter, or a laboratory gas analysis detects, H₂S in the gas stream at concentrations at or above 100 parts per million (“ppm”), the Operator will calculate the radius of exposure to any Building Unit, High Occupancy Building Unit, or Designated Outside Activity Area.

- (1) Radius of exposure will be calculated pursuant to Bureau of Land Management (“BLM”) Onshore Order No. 6 (Jan. 22, 1991). Only the 1991 version of Onshore Order 6 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, CO 80203. In addition, these materials are available from the BLM Colorado State Office, 2850 Youngfield St., Lakewood, CO 80215, and are available online at https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder6.pdf.
- (2) If insufficient data exists to calculate a radius of exposure, the Operator will assume the radius of exposure is 3,000 feet.
- (3) Operators will perform gas stream laboratory analysis if any concentration of H₂S of 20 ppm or greater is detected by using field measurement devices during drilling, completion, or production operations. Operators will report any gas stream laboratory analysis greater than 1 ppm H₂S to the Director and the Relevant and Proximate Local Government(s). If the Operator ever detects H₂S concentrations greater than 1 ppm, the Operator will repeat gas stream laboratory analysis annually.

c. H₂S Public Protection Plan. A public protection plan is required if:

- (1) The 100 ppm radius of exposure is greater than 50 feet and there is a Building Unit, High Occupancy Building Unit, or Designated Outside Activity Area within the radius of exposure;
- (2) The 100 ppm radius of exposure is equal to or greater than 3,000 feet and includes any publicly-maintained road; or
- (3) The Director determines that a public protection plan is necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources.

d. H₂S Drilling Operations Plan.

- (1) When proposing to drill a Well in areas where H₂S gas can reasonably be expected to be encountered, Operators will submit a H₂S drilling operations plan with their Form 2, unless the plan was already submitted with their Form 2A, pursuant to Rule 304.c.(10).
- (2) Operators will prepare the H₂S drilling operations plan pursuant to BLM Onshore Order No. 6, as incorporated by reference in Rule 612.b.(1).

e. Designated H₂S Locations. If an Operator ever measures H₂S gas stream concentrations of 100 ppm or greater at a Well, the Well is a designated H₂S location. All designated H₂S locations will be designed and operated in accordance with BLM Onshore Order No. 6, as incorporated by reference in Rule 612.b.(1). Designated H₂S locations will have:

- (1) Signs indicating the presence of H₂S not less than 200 feet or more than 500 feet from the entrance of the location;
- (2) H₂S monitoring with audible and visible alarms at 10 ppm of H₂S;

- (3) At least one wind indicator; and
- (4) With landowner approval, adequate fencing.

f. Operations in Designated H₂S Locations.

- (1) In a designated H₂S location, Operators will employ a secondary means of immediate Well control at all Wells that are known to have H₂S through use of a christmas tree or downhole completion equipment. The equipment will allow downhole accessibility (reentry) under pressure for permanent Well control. When the presence of H₂S is detected during drilling in formations not tested, completed, or produced, the Operator will report depth intervals, concentrations measured at surface or within drilling Fluid, and the control measures used.
- (2) At Oil and Gas Locations producing gas with greater than 100 ppm H₂S, Operators will monitor all storage Tanks. Any headspace field measurement or laboratory analysis greater than 500 ppm H₂S, or 10 ppm H₂S in ambient air, will require mitigation measures to control and minimize accumulation within the storage Tank.
- (3) All operations at an Oil and Gas Location with potential H₂S concentrations greater than 100 ppm will:
 - A. Use equipment that can withstand the effects and stress of H₂S;
 - B. Be conducted pursuant to American National Standards Institute (“ANSI”)/National Association of Corrosion Engineers (“NACE”) Standard MR0175/ISO 15156-2015-SG, Petroleum and natural gas industries – Materials for use in H₂S-containing environments in oil and gas production (2015), or some other Director approved standard for selection of metallic equipment. Only the 2015 version of ANSI/NACE Standard MR0175/ISO 15156-2015-SG applies to this Rule; later amendments do not apply. All material 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, CO 80203. In addition, these materials are available from NACE International, 15835 Park Ten PI, Houston, TX 77084; and
 - C. If applicable, use adequate protection by chemical inhibition or such other methods that control or limit H₂S’s corrosive effects.
- (4) Operators in designated H₂S locations will conduct a laboratory analysis of the gas stream for H₂S at least monthly. If the H₂S concentration increases by greater than 25%, the Operator will recalculate the radius of exposure and notify the Director and the Relevant and Proximate Local Government(s).

g. Operator Reports of H₂S.

- (1) Operators will report on a Form 42, Field Operations Notice – Notice of H₂S on an Oil and Gas Location any laboratory analysis indicating the presence of H₂S gas to the Director within 48 hours. Upon receipt of the Form 42, the Director will notify the Relevant and Proximate Local Government(s).
- (2) If a laboratory analysis indicates any concentrations of H₂S gas greater than 100 ppm in the gas stream, or headspace field measurement or laboratory analysis greater than 500 ppm H₂S, or 10 ppm H₂S in ambient air, the Operator will report such findings to the Director on a Form 4, including the information required in Rules 612.b–d, as applicable, within 45 days.

- h. Unless deemed an immediate operational need for safety reasons and the release does not pose a risk to public safety, Operators may only intentionally release H₂S gas with prior Director approval of a Form 4. The Form 4 will include a proposed air monitoring plan for H₂S. If combustion or Flaring is proposed, the air monitoring plan will include a SO₂ by-product detection plan.
- i. If an intentional release of H₂S gas occurs due to Upset Conditions or malfunctions, the Operator will notify the Director, the Relevant and Proximate Local Government(s), and the local emergency response agency orally within 24 hours, followed by the filing of a Form 4 within 5 days.
- j. All H₂S monitoring, mitigation, and safety equipment will be maintained and functioning in good working order at all times.
- k. **Temporary Abandonment of a H₂S Well.**
 - (1) Prior to temporarily abandoning a Well with potential concentrations of greater than 100 ppm H₂S in its gas stream, the Operator will file a Form 4, Notice of Temporarily Abandoned Status to obtain the Director's approval.
 - (2) Operators will install a cast iron bridge plug and maintain H₂S monitoring and telemetry equipment when temporarily abandoning a Well with potential concentrations of greater than 100 ppm H₂S in its gas stream.

613. GRADE 1 GAS LEAK REPORTING

An Operator will initially report to the Director a Grade 1 Gas Leak from a Flowline pursuant to Rule 912.b.(1).D and will submit the Form 19, Spill/Release Report document number on the Form 44, Flowline Report for the Grade 1 Gas Leak.

614. COALBED METHANE WELLS

- a. **Assessment and Monitoring of Plugged and Abandoned Wells Within 1/4 mile of Proposed Coalbed Methane Well.**
 - (1) Based upon examination of Commission and other publicly available records, Operators will identify all Plugged and Abandoned Wells located within 1/4 mile of a proposed coalbed methane ("CBM") Well. The Operator will assess the risk of leaking gas or water to the ground surface or into subsurface water resources, taking into account plugging and cementing procedures described in any recompletion or Plug and Abandonment report filed with the Commission. The Operator will notify the Director of the results of the assessment of the plugging and cementing procedures. The Director will review the assessment and take appropriate action to pursue further investigation and Remediation if warranted and pursuant to the Colorado Oil and Gas Conservation and Environmental Response Fund.
 - (2) Operators will conduct a soil gas survey at all Plugged and Abandoned Wells located within 1/4 mile of a proposed CBM Well prior to production from the proposed CBM Well and again 1 year and thereafter every 3 years after production has commenced. Operators will submit the results of the soil gas survey to the Director within 3 months of conducting the survey.
- b. **Coal Outcrop and Coal Mine Monitoring.**
 - (1) If the CBM Well is within 2 miles of the outcrop of the stratigraphic contact between the

coal-bearing formation and the underlying formation, or within 2 miles of an active, inactive, or abandoned coal mine, then prior to drilling the CBM Well, the Operator will determine whether there are gas seeps, springs, or water seeps that discharge from the coal-bearing formation in the area by:

- A. Making a good faith effort to obtain the access necessary to survey the outcrop or mine;
 - B. Reviewing publicly available geologic and hydrogeologic data; and
 - C. Interviewing the Surface Owner(s).
- (2) If a gas seep is identified during the survey, then the Operator will survey its location and areal extent pursuant to Rule 216, and determine the concentration of the soil gas. If possible, the Operator will collect a sample of gas from the seep for compositional analysis and stable isotope analysis of the gas pursuant to 615.e.(4). Thereafter, the Operator will inspect the gas seep, survey its areal extent, and measure soil gas concentrations annually, if access can be obtained. Within 3 months of its completion of the field work, the Operator will submit the results of the outcrop or mine monitoring to the Director in an electronic data deliverable format via a Form 43, Analytical Sample Submittal and, if necessary, via a Form 4. The Operator will concurrently provide the same information to the Surface Owner.
- (3) If a spring or water seep is identified during the survey, then the Operator will survey its location and areal extent pursuant to Rule 216, measure the flow rate, photograph the feature, and collect and analyze a water sample pursuant to Rule 615.e. Thereafter, the Operator will inspect the spring or water seep, survey its areal extent, and measure its flow rate annually, if access can be obtained. Within 3 months of its completion of the field work, the Operator will submit the results of the outcrop or mine monitoring to the Director in an electronic data deliverable format via a Form 43 and, if necessary, via a Form 4. The Operator will concurrently provide the same information to the Surface Owner.
- (4) If a gas seep is identified during the survey, the Director will advise the Surface Owner(s), Relevant Local Government, Colorado Geological Survey (“CGS”), and the Colorado Division of Reclamation, Mining, and Safety (“DRMS”), as appropriate, of the findings. In collaboration with state, local, and private interests, the CGS, DRMS, and the Commission may elect to develop a Geologic Hazard survey and determine whether the area should be recommended to be designated as a Geologic Hazard pursuant to § 24-65.1-103, C.R.S.
- c. **Prior to Producing – Static Bottom-Hole Pressure Survey.** Prior to producing the Well, the Operator will obtain a static bottom-hole pressure test on at least the first Well drilled on a government quarter section. The survey will be conducted by either a direct static bottom-hole pressure measurement or by a static Fluid level measurement. The data acquired by the Operator and a description of the procedures used to gather the data will be reported on a Form 13, Bottom Hole Pressure, and submitted with the Form 5A, Completed Interval Report, filed with the Director. After reviewing the quality of the static bottom-hole pressure data and the adequacy of the geographic distribution of the data, or at the request of the Operator, the Director may vary the number of Wells subject to the static bottom-hole pressure survey requirement. If an application for increased Well density or down spacing is filed with the Commission, then additional testing may be required.
- d. **CBM Monitoring.** If a conventional gas Well or Plugged and Abandoned Well exists within 1/4 mile of a proposed CBM Well, then in addition to the water sources described in Rule 615.b, the 2 closest water wells within a 1/2 mile radius of the conventional gas Well or the Plugged and Abandoned Well will be sampled pursuant to Rules 615.c–f.

- (1) If possible, the water wells selected should be on opposite sides of the conventional gas Well or the Plugged and Abandoned Well not exceeding a 1/2 mile radius. If water wells on opposite sides of the conventional gas Well or the Plugged and Abandoned Well cannot be identified, then the 2 closest wells within a 1/2 mile radius of the conventional gas Well or the Plugged and Abandoned Well will be sampled.
 - (2) If 2 or more conventional Wells or Plugged and Abandoned Wells are located within 1/4 mile of the proposed CBM Well, then the conventional Well or the Plugged and Abandoned Well closest to a proposed CBM Well will be used for selecting water wells for sampling.
 - (3) If there are no conventional gas Wells or Plugged and Abandoned Wells located within a 1/4 mile radius of the proposed CBM Well this Rule 614.d will not apply.
- e. **Bradenhead Testing.** An Operator of a CBM Well will comply with Rule 419, except as modified by this Rule 614.e. The appropriate regulatory agency will determine remedial requirements. The bradenhead testing requirement will not apply if the Operator demonstrates to the satisfaction of the Director annular cement coverage greater than 50 feet above the base of surface casing and zonal isolation is confirmed by reliable evidence such as a cement bond log or cementing ticket indicating that the height of cement coverage is 50 feet above the base of the surface casing, and zonal isolation is confirmed by two consecutive bradenhead tests that the Operator conducts at least 12 months apart. Before beginning a bradenhead test, the Operator will shut-in the bradenhead annulus for a minimum shut-in period of 7 days.

615. GROUNDWATER BASELINE SAMPLING AND MONITORING

a. Applicability and Effective Date.

- (1) This Rule applies to oil Wells, gas Wells (“Oil and Gas Wells”), Multi-Well Sites, and Class II UIC Wells for which a Form 2, or Form 4, Notice to Recomplete, is submitted or pending on or after January 15, 2021. Oil and Gas Wells, Multi-Well Sites, and Class II UIC Wells operating under a Form 2 approved prior to January 15, 2021, will continue to follow the sampling protocols required by their permits at the time that the Form 2 was approved.
- (2) Nothing in this Rule 615 is intended, and will not be construed, to preclude or limit the Director from requiring Groundwater sampling or monitoring at other Production Facilities consistent with other applicable Commission Rules, including but not limited to the oil and gas location assessment process, and other processes in place pursuant to the Commission’s 900 Series Rules (Form 15, Earthen Pit Report/Permit, Form 27, Site Investigation and Remediation Workplan, and Form 28, Centralized E&P Waste Management Facility Permit).
- (3) An Operator may elect, or the Director may require an Operator to install one or more Groundwater monitoring wells to satisfy, in full or in part, the requirements of Rule 615.b, but installation of monitoring wells is not required under this Rule 615.

b. Sampling Locations.

Initial baseline samples and subsequent monitoring samples will be collected from all Available Water Sources, up to a maximum of 4, within a 1/2 mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well. If more than 4 Available Water Sources are present within a 1/2 mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well, the Operator will select the 4 sampling locations based on the following criteria:

- (1) **Proximity.** Available Water Sources closest to the proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well are required.

- (2) **Type of Water Source.** Well-maintained domestic water wells are required over other Available Water Sources.
 - (3) **Orientation of Sampling Locations.** To the extent Groundwater flow direction is known or reasonably can be inferred, sample locations from both down-gradient and up-gradient are preferred over cross-gradient locations. Where Groundwater flow direction is uncertain, sample locations should be chosen in a radial pattern from a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well.
 - (4) **Multiple Identified Aquifers Available.** Where multiple defined Aquifers are present, sampling the deepest and shallowest identified Aquifers is required.
 - (5) **Condition of Water Source.** An Operator is not required to sample Water Sources that are determined to be improperly maintained, nonoperational, or have other physical impediments to sampling that would not allow for a representative sample to be safely collected or would require specialized sampling equipment (e.g., Shut-In Wells, wells with confined space issues, wells with no tap or pump, non-functioning wells, intermittent springs).
- c. **Inability to Locate an Available Water Source.** Prior to spudding, an Operator may request an exception from the requirements of this Rule 615 by filing a Form 4 for the Director's review and approval if:
- (1) No Available Water Sources are located within 1/2 mile of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well;
 - (2) The only Available Water Sources are determined to be unsuitable pursuant to Rule 615.b.(5). An Operator seeking an exception on this ground will document the condition of the Available Water Sources it has deemed unsuitable; or
 - (3) The owners of all Water Sources suitable for testing under this Rule refuse to grant access despite an Operator's reasonable, good faith efforts to obtain consent to conduct sampling. An Operator seeking an exception pursuant to this Rule 615.c.(3) will document the efforts used to obtain access from the owners of suitable Water Sources.
 - (4) If the Director takes no action on the Form 4 within 10 business days of receipt, the requested exception from the requirements of this Rule 615.c will be deemed approved.
- d. **Timing of Sampling.**
- (1) Initial sampling will be conducted within 12 months prior to setting conductor pipe in a Well or if no conductor is present prior to spudding the first Well on a Multi-Well Site, or commencement of drilling a Class II UIC Well.
 - (2) **Subsequent Monitoring.** One subsequent sampling event will be conducted at the initial sample locations between 6 and 12 months, and a second subsequent sampling event will be conducted between 60 and 72 months following completion of the Well or Class II UIC Well, or the last Well on a Multi-Well Site. Additional subsequent samples will be collected every 5 years (57 to 63 month interval) for the life of the Well. A post abandonment sample will be collected 6 to 12 months after the Oil and Gas Well has been Plugged and Abandoned. Wells that are drilled and abandoned without ever producing hydrocarbons are exempt from subsequent monitoring sampling under this Rule 615.d.(2).
 - (3) **Previously Sampled Water Sources.** In lieu of conducting the initial sampling required pursuant to Rule 615.d.(1), or the second subsequent sampling event required pursuant to

Rule 615.d.(2), an Operator may rely on water sampling analytical results obtained from an Available Water Source within the sampling area provided:

- A. The previous water sample was obtained within the 18 months preceding the initial sampling event required pursuant to Rule 615.d.(1), or any subsequent sampling event required pursuant to Rule 615.d.(2);
 - B. The sampling procedures, including the constituents sampled for, and the analytical procedures used for the previous water sample were substantially similar to those required pursuant to Rules 615.e.(1) & (2), below; and
 - C. The Director timely received the analytical data from the previous sampling event.
- (4) The Director may require additional sampling at any time as a result of information indicating a potential change in or impact to groundwater.

e. Sampling Procedures and Analysis.

- (1) Sampling and analysis will be conducted in conformance with an accepted industry standard pursuant to Rule 913.b.(2). A model Sampling and Analysis Plan (“COGCC Model SAP”) will be posted on the Commission’s website, and will be updated periodically to remain current with evolving industry standards. Sampling and analysis conducted in conformance with the COGCC Model SAP will be deemed to satisfy the requirements of this Rule 615.e.(1). Upon request, an Operator will provide its sampling protocol to the Director.
- (2) The analyses for samples collected as required by Rule 615 will include:
 - A. pH;
 - B. Specific conductance;
 - C. Total dissolved solids (“TDS”);
 - D. Dissolved gases (methane, ethane, and propane);
 - E. Alkalinity (total, bicarbonate, and carbonate as CaCO₃);
 - F. Major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrite as N, and phosphorus);
 - G. Major cations (calcium, iron, magnesium, manganese, potassium, and sodium);
 - H. Other elements (barium, boron, selenium, and strontium);
 - I. Presence of bacteria (iron related, sulfate reducing, and slime forming);
 - J. Total petroleum hydrocarbons (“TPH”) as total volatile hydrocarbons (C₆ to C₁₀) and total extractable hydrocarbons (C₁₀ to C₃₆); and
 - K. BTEX compounds (benzene, toluene, ethylbenzene, and xylenes (“BTEX”)).
- (3) Field observations such as odor, water color, sediment, bubbles, and effervescence as well as the presence or absence of H₂S gas will be documented. The location of the sampled Water Sources will be surveyed pursuant to Rule 216.

(4) Dissolved Gas Detections. If a free or dissolved gas (methane, ethane, or propane) concentration greater than 1.0 milligram per liter (“mg/l”) is detected in a water sample, gas compositional analysis and stable isotope analysis of the gas will be performed to determine gas type.

A. The compositional analysis should include:

- i. hydrogen;
- ii. argon;
- iii. oxygen;
- iv. carbon dioxide;
- v. nitrogen;
- vi. methane (C1);
- vii. ethane (C2);
- viii. ethene (C₂H₄);
- ix. propane (nC₃);
- x. isobutane (iC₄);
- xi. butane (nC₄);
- xii. isopentane (iC₅);
- xiii. pentane (nC₅);
- xiv. hexanes +;
- xv. Specific gravity; and
- xvi. British Thermal Units (BTU).

B. Stable isotope analyses should include:

- i. delta D of C1;
- ii. delta 13C of C1;
- iii. delta 13C of C2;
- iv. delta 13C of C3;
- v. delta 13C of iC₄ (if available);
- vi. delta 13C of nC₄ (if available);
- vii. delta 13C of iC₅ (if available);

- viii. delta 13C of nC5 (if available); and
 - ix. delta 13C of CO₂.
- C. The Operator will notify the Director by submitting a Form 42, Field Operations Notice – Water Sample Reporting, with a copy sent to the owner of the water well immediately if:
- i. The test results indicated thermogenic or a mixture of thermogenic and biogenic gas;
 - ii. The methane concentration increases by more than 5.0 mg/l between sampling periods; or
 - iii. The methane concentration is detected at or above 10 mg/l.
- D. The Operator will notify the Director immediately by Form 42 – Water Sample Report and provide a copy of the Form 42 – Water Sample Report and the test results to the water well owner, if BTEX compounds or TPH are detected in a water sample.
- f. **Sampling Results.** Copies of all final laboratory analytical results will be provided to the Director and the water well owner or landowner within 3 months of collecting the samples. The analytical results including PDF of lab results, the surveyed sample Water Source locations, and the field observations will be submitted to the Director in an electronic data deliverable format approved by the Director along with a PDF of the lab report via Form 43.
- (1) The Director will make such analytical results publicly available by posting on the Commission's website or through another means announced to the public.
- g. Upon request, the Director will also make the analytical results and surveyed Water Source locations available to the Local Government of the jurisdiction in which the groundwater samples were collected, in the same electronic data deliverable format.