100 SERIES
DEFINITIONS

CDPHE means the Colorado Department of Public Health and Environment.

CPW means the Colorado Parks and Wildlife.

CHEMICAL INVENTORY means a list of the Chemical Products (including Safety Data Sheets) brought to a Well Site for use downhole during drilling, completion, and workover operations, including fracture stimulations, and the maximum capacity of fuel stored on the Oil and Gas Location during those operations. The Chemical Inventory will include how much of the Chemical Product was used, how it was used, and when it was used.

EPA means the U.S. Environmental Protection Agency.

GLOBALLY HARMONIZED DATA SHEET means the current version of the written or printed global standard of classification for hazardous chemicals.

PRINCIPAL AGENT means the Operator representative authorized to accept and be served with notice from the Commission, or from other persons authorized under the Act.

WELL RECORDS means all records related to the drilling, redrilling, deepening, repairing, plugging or abandoning of a Well, all other Well operations, and all alterations to casing and cement.

GENERAL PROVISIONS

201. EFFECTIVE SCOPE OF RULES AND REGULATIONS

a. The Commission's rules are promulgated to regulate Oil and Gas Operations in a manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment and wildlife resources, and to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. These Rules are effective throughout the State of Colorado and are in force in all pools and fields unless the Commission amends, modifies, alters or enlarges them through Orders or Rules that apply to specific individual pools or fields.

b. **Compliance.** The Operator of any Oil and Gas Location, Oil and Gas Facility, Well, or any seismic, core, or other exploratory holes, whether cased or uncased, will comply with all applicable Commission Rules and will ensure compliance by their contractors and subcontractors.

c. Nothing in the Commission's Rules constrains the legal authority conferred to Local Governments by §§ 29-20-104, 30-15-401, C.R.S., or any other statute. Local Government regulations may be more protective or stricter than state requirements. If a Local Government applies a standard that is less protective of public health, safety, welfare, the environment, or wildlife resources than a state requirement governing the same Oil and Gas Location, Oil and Gas Facility or Oil and Gas Operations, the Operator will comply with the stricter state requirement.

d. These rules will not apply to:

(1) Indian trust lands and minerals; or

(2) The Southern Ute Indian Tribe within the exterior boundaries of the Southern Ute Indian Reservation. The Commission's Rules will apply to non-Indians conducting Oil and Gas Operations on lands within the exterior boundaries of the Southern Ute Indian Reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Southern Ute Indian Tribe, regardless of whether such lands are communitized or pooled.

e. The State of Colorado will exercise criminal and civil jurisdiction within the Town of Ignacio, Colorado or within any other municipality within the Southern Ute Indian Reservation incorporated under the laws of Colorado, as provided by Sec. 5, Public Law No. 98-290 (1984).

f. **Severability.** If any portion of the Commission's Rules are found to be invalid, unconstitutional, or otherwise enjoined or overturned through judicial review, the Commission intends for the remaining portion of the Rules to remain in force and effect.

g. **Incorporated Materials.** Where referenced herein, the Commission's Rules incorporate by reference material originally published elsewhere. Such incorporation does not include later amendments to or editions of the referenced material. Pursuant to § 24-4-103(12.5), C.R.S., the Commission maintains copies of the complete text of the incorporated materials for public inspection during regular business hours. Copies of the complete text and information regarding how the incorporated material may be obtained or examined is available at the Commission's office located at 1120 Lincoln Street, Suite 801, Denver, Colorado 80203.

202. OFFICE AND DUTIES OF DIRECTOR

The office of Director of the Commission is hereby created. The Director is responsible for all Commission staff functions. The Director serves as the custodian of the Commission's records. Additional duties of the Director will be as determined from time to time by the Chair.

203. OFFICE AND DUTIES OF SECRETARY

The office of Secretary to the Commission is hereby created. The duties of the Secretary will be as determined from time to time by the Chair.

204. INSPECTION POWERS.

The Director has the right at all reasonable times to go upon and inspect any Oil and Gas Location, Oil and Gas Facility, disposal facility, or transporter facility, and any associated records, for the purpose of making any investigation or conducting any tests to ascertain compliance with the provisions of the Act or the Commission's Rules or any special field rules. Any findings of a Commission Rule violation will be reported to the Commission.

205. OPERATOR REGISTRATION

a. **Form 1: Registration for Oil and Gas Operations.** Prior to the commencement of its operations, all producers, Operators, transporters, refiners, gasoline or other extraction plant Operators, and initial purchasers who are conducting operations subject to this Act in the State of Colorado, will, for purposes of the Act, file a Form 1, Registration for Oil and Gas Operations with the Director in the manner and form approved by the Commission. Any producer, Operator, transporter, refiner, gasoline or other extraction plant operator, and initial purchaser conducting operations subject to the Act who has not previously filed a Form 1, will do so immediately. Any entity providing financial assurance for oil and gas Operators in Colorado will file a Form 1 with the Director. All changes of address of any party required to file a Form 1 will be immediately reported via a new Form 1.

b. Form 1A: Designation of Agent.

(1) All Operators will file a Form 1A, Designation of Agent to designate:

A. A Principal Agent, who is an employee of the Operator, and

B. One or more agents that the Operator approves to serve as its representative(s).

(2) Form 1A designations will remain in effect until terminated in writing via a new Form 1A.

(3) All changes to the Form 1A will be immediately reported via a new Form 1A.

206. RECORDKEEPING AND ACCESS TO RECORDS

a. Upon request by the Director or the Commission all Operators will submit any record, information, or data required to be maintained under the Commission's Rules within 3 business days in a readily-reviewable format. If the document is not within the Operator's possession, the Director may extend the response time.

b. All producers, Operators, transporters, refiners, gasoline or other extraction plant operators, initial purchasers of oil and gas within this State, and any other persons or entities subject to regulation under the Commission's Rules will keep accurate and complete records as required by the Commission's Rules. The Director and the Commission will have access to these records upon request. Such records include, but are not limited to:

(1) Any record required to be retained by any of the Commission's Rules;

(2) All reports required by the Commission's Rule to be filed with the Director or Commission;

(3) Natural gas meter calibration reports;

(4) Oil meter calibration reports;

(5) Well records;

(6) Chemical Product records; and

(7) All such records and reports as may be requested by the Director or the Commission.

c. Well Records will show all the formations penetrated, the content and quality of oil, gas or water in each formation tested, and the grade, weight and size, and landed depth of casing and type and volume of cement used in drilling each Well on the leased premises, and any other information obtained in the course of a Well operation.

(1) **Well Records Confidentiality.** An Operator may request confidentiality for an exploratory or Wildcat Well by submitting a Form 4, Sundry Notice. If the Director determines that the Well qualifies as an exploratory or Wildcat Well, the Form 5, Drilling Completion Reports, and Form 5A, Completed Interval Reports, and Form 7, Operators Monthly Reports of Operations, and all logs run will be considered as confidential geological or geophysical data pursuant to § 24-72-204(3)(a)(IV), C.R.S., and will be kept confidential for 6 months after the date of Well completion, unless the Operator gives written permission to release the information at an earlier date.

d. For purposes of Rule 206.b.(6), Chemical Products Records include:

(1) Safety Data Sheets (SDS), or Globally Harmonized Data Sheets for any Chemical Products brought to an Oil and Gas Location for use downhole during drilling, completion, well stimulation, workover operations and production operations, excluding Hydraulic Fracturing Treatments. Operators will maintain a Chemical Inventory for each Chemical Product used or stored on an Oil and Gas Location during a quarterly reporting period, organized by Well Site, in an amount exceeding 500 pounds.

(2) The 500 pound reporting threshold in Rule 206.d.(2) is based on the cumulative maximum amount of a Chemical Product present at the Oil and Gas Location during the quarterly reporting period. Entities maintaining Chemical Inventories under this section will update these inventories quarterly throughout the life of the Well Site.

(3) Operators will maintain the records covered by Rule 206.c. and d. in a readily retrievable format at the Operator's local field office.

e. **Transfer of Records.** All records and reports required by the Commission's Rules will be transferred to and maintained by any subsequent Operator.

f. **Maintenance of Records.**

(1) Unless otherwise specified by Commission Rule, Operators will maintain and keep all records, reports, and underlying data required by these Rules for a period of 5 years.

(2) Operators will maintain and keep Chemical Product records and Well Records for 5 years after the plugging and abandonment of the applicable Well.

(3) Operators will maintain and keep Chemical Product records for 5 years after the closure an Oil and Gas Location.

207. REPORTS.

Any report required under the Commission's Rules or requested by the Director or the Commission will be timely filed, accurate, complete, and comply with the requirements set forth in the Commission's Rule or any requirement set by the Director or the Commission.

208. CHEMICAL DISCLOSURE.

a. Upon request by the Director, the Commission, a Relevant Local Government, Governmental Agency, an emergency responder, or a health professional, the Operator, vendor, or service provider will provide a list of the chemical constituents contained in a Chemical Product.

(1) Such request may be made as a result of a spill or release, a complaint from a potentially adversely Affected Person, or when necessary to protect public health, safety, welfare, the environment, and wildlife resources, and protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(2) Disclosure of the Chemical constituents contained in a Chemical Product will only be made to a health professional when requested for the purpose of diagnosis or treatment of an individual who may have been exposed to a chemical used at an Oil and Gas Location.

b. If the Operator, vendor, or service provider designates the information provided under Rule 208.a. as a Trade Secret Chemical, and the Director approves the Trade Secret Chemical designation, the information will be considered confidential under § 24-72-204(3)(a)(IV), C.R.S.

c. Hydraulic Fracturing Chemical Disclosure.

(1) Vendor and Service Provider Disclosures. A service provider who performs any part of a Hydraulic Fracturing Treatment and a vendor who provides hydraulic fracturing additives directly to the Operator for a Hydraulic Fracturing Treatment will, with the exception of information claimed to be a Trade Secret Chemical Product, furnish the Operator with any information needed for the Operator to complete the Chemical Disclosure Registry form and post the form on the Chemical Disclosure Registry. Such information will be provided as soon as possible within 30 days following the conclusion of the Hydraulic Fracturing Treatment and in no case later than 90 days after the commencement of such Hydraulic Fracturing Treatment.

(2) Operator Disclosures. Within 60 days following the conclusion of a Hydraulic Fracturing Treatment, and in no case later than 120 days after the commencement of such Hydraulic Fracturing Treatment, the Operator of the Well must complete the Chemical Disclosure Registry form and post the form on the Chemical Disclosure Registry, including:

A. the Operator name;

B. the date of the Hydraulic Fracturing Treatment;

C. the county in which the Well is located;

D. the API number for the Well;

E. the Well name and number;

F. the longitude and latitude of the wellhead;

G. the true vertical depth of the Well;

H. the total volume of water used in the Hydraulic Fracturing Treatment of the Well or the type and total volume of the base fluid used in the Hydraulic Fracturing Treatment, if something other than water;

I. each hydraulic fracturing additive used in the Hydraulic Fracturing Fluid and the trade name, vendor, and a brief descriptor of the intended use or function of each hydraulic fracturing additive in the hydraulic fracturing fluid;

J. each chemical intentionally added to the base fluid;

K. the maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid; and

L. the chemical abstract service number for each chemical intentionally added to the base fluid, if applicable.

(3) **Ability to Search for Information.** The Chemical Disclosure Registry will allow the Director and the public to search and sort the registry for Colorado information by geographic area, ingredient, chemical abstract service number, time period, and Operator.

209. TESTS AND SURVEYS

a. **Tests and Surveys.** When deemed necessary or advisable, the Commission is authorized to require that tests or surveys be made to protect public health, safety, and welfare, the environment and wildlife resources, and protect against adverse environmental impacts on any air, water soil, or biological resource resulting from Oil and Gas Operations. If the Rules do not provide a timeline for conducting the test or survey, the Commission will designate the time allowed to the Operator for compliance.

b. **Bradenhead Test Areas. [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]**

(1) The Commission may approve specific fields or portions of fields as bradenhead test areas.

A. The Director may propose specific fields or portions of fields as bradenhead test areas by notice to all operators on record within the area and by publication.

B. The proposed designation, if no protests are timely filed, will be placed upon the Commission consent agenda for the next regular meeting of the Commission following the month in which such notice was given. The Commission will hear the proposed designation in accordance with Rule 519.

C. If a protest is timely filed, the Commission will hear the proposed designation in accordance with the 500 Series Rules.

(2) The Commission order will describe the bradenhead testing or monitoring required and become effective upon approval by the Commission unless the Commission orders otherwise.

210. CORRECTIVE ACTION

a. The Director or Commission will require correction of any condition necessary to protect and minimize adverse impacts to public health, safety, and welfare, the environment and wildlife resources, and protect against adverse environmental impacts on any air, water soil, or biological resource, or any condition that the Director or Commission has reasonable cause to believe is in violation of the Commission's Rules. The Director or Commission may exercise its discretion to set forth the manner in which the condition is to be remedied.

b. When a Field Inspection Report includes a corrective action, upon completion of that corrective action the Operator will submit to the Director a Field Inspection Report Resolution Form (FIRR).

211. PLUGGING AND ABANDONMENT OF WELLS AND CLOSURE OF OIL AND GAS FACILITIES AND LOCATIONS

a. An Owner or Operator of a Well will plug and abandon the Well if the Director determines that plugging and abandoning is necessary to protect or minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources, and protect against adverse environmental impacts on any air, water soil, or biological resource, or when the Well is no longer used or useful.

b. An Owner or Operator of an Oil and Gas Location will permanently close an Oil and Gas Location or Oil and Gas Facility if the Director determines that such closure is necessary to protect or minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources, and protect against adverse environmental impacts on any air, water soil, or biological resource, or when the Oil and Gas Location or Oil and Gas Facility is no longer used or useful.

c. If the Director requires an Operator to take action pursuant to Rules 211.a. or 211.b., 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 Rules 211.a. or 211.b. 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 believe that an Operator's actions impacted or threatened to impact public health, safety, welfare, the environmental, or wildlife resources.

d. If an Operator does not appeal the Director's decision pursuant to Rule 211.c, the Director will report the decision at its next regularly scheduled hearing.

212. PROTECTION OF COAL SEAMS AND WATER-BEARING FORMATIONS [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

In the conduct of oil and gas operations each owner will exercise due care in the isolation of coal seams and groundwater.

Special precautions will be taken in drilling and abandoning wells to guard against any loss of artesian water from the stratum in which it occurs and the contamination of groundwater by produced water, liquid hydrocarbons, or natural gas. Before any oil or gas well is completed, all oil, gas, and groundwater bearing formations above and below the producing formation(s) will be isolated to prevent the intermingling of formation fluids and gases between formations.

213. NOTICE TO THE DIRECTOR AND COMMISSION

a. Any notice required to be filed with the Commission will be filed in the manner and time set forth by the Commission's Rules.

b. **Emergencies**.

(1) In case of an emergency where the delay caused by obtaining written approval would endanger public health, safety, welfare, the environment, or wildlife, any notice or information required by the Commission's Rules may be given to the Director orally.

(2) If notice or information is provided orally in the case of emergency, Operators must provide to the Director the same information in writing at the earliest possible time, unless a Commission Rule establishes a different timeframe. In the case of such an emergency, the Director or Commission may approve the operation or change to an approved operation orally, which will be later confirmed in writing.

(3) If public health, safety, welfare, the environment, or wildlife is threatened, the Operator responsible for the operation causing such threat must immediately notify the Director electronically and orally.

214. NAMING OF FIELDS

All oil and gas fields discovered in the State subsequent to the adoption of the Commission's Rules will be named by the Director or at the Director's direction.

215. LOCAL GOVERNMENTAL DESIGNEE

Each Local Government which designates an office for the purposes set forth in the 100 Series will provide the Commission written notice of such designation, including the name, address and telephone number, electronic mail address, local emergency dispatch and other emergency numbers of the Local Governmental Designee. It will be the responsibility of such Local Governmental Designee to ensure that all documents provided to the Local Governmental Designee by oil and gas Operators and the Commission or the Director are distributed to the appropriate persons and offices.

216. GLOBAL POSITIONING SYSTEMS

Global Positioning Systems (GPS) may be used to locate facilities used in Oil and Gas Operations provided they meet the following minimum standards:

a. GPS instruments are differential grade.

b. GPS instruments are capable of 1 meter horizontal positional accuracy after differential correction.

c. The Operator will report an accuracy value (in meters) or position dilution of precision (PDOP) value with all submitted GPS data. Accuracies of 1.0 meter or less and PDOP readings of 6.0 or less are acceptable.

d. Elevation mask (lowest acceptable height above the horizon) will be no less than 15 degrees.

e. Latitude and longitude coordinates will be provided in decimal degrees with an accuracy and precision of 5 decimals of a degree using the North American Datum (NAD) of 1983 (e.g.; latitude 37.12345 N, longitude 104.45632 W).

f. Raw and corrected data files will be held for a period of 3 years.

g. Measurements will be made by a trained GPS Operator familiar with the theory of GPS, the use of GPS instrumentation, and typical constraints encountered during field activities.

217. Form 8. OIL AND GAS CONSERVATION LEVY

a. On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by § 34-60-122(1)(a), C.R.S., will file a Form 8, Oil and Gas Conservation Levy with the Director. The Form 8 will show, by Operator, the volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery. No Form 8 will be required when the charge imposed is zero mill ($0.0000) per dollar value. The levy will be an amount fixed by order of the Commission.

b. The levy amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas conservation and environmental response fund. The present charge imposed, as of April 1, 2018, is $0.0011 per dollar value.

218. FORM 9, TRANSFER OF PERMITS

a. An Operator may transfer any Form 2, Form 2A, and any related Commission permit or license associated with its Oil and Gas Operations (collectively "Permits") to a successor in interest by filing a Form 9, Transfer of Permits, with the Commission at least 30 days before the proposed transfer date. The Form 9 will include:

(1) The specific date for transfer of all Permits.

(2) The complete list of all Wells, Oil and Gas Locations, facilities, injection Wells and any related facilities registered with the Commission that are proposed for transfer.

(3) Whether the current Operator or the successor in interest will be responsible for compliance with the Commission's Rules at each facility listed under Rule 218.a.(2). If a prior Operator other than the current Operator retains responsibility for any facility listed under Rule 218.a.(2), the Form 9 will include a signed attestation from the prior Operator acknowledging the scope of the prior Operator's liability.

(4) The amount of financial assurance required by the Commission's Rules that the successor in interest will submit to the Commission prior to the date of transfer.

(5) An acknowledgment that upon the date of transfer, the successor in interest assumes all compliance and reclamation responsibilities for the Permits, and will conduct all Oil and Gas Operations in compliance with the Act, the Commission's Rules, and all terms and conditions of the existing Permits and Commission orders. This acknowledgment will specifically identify a complete list of all open remediation projects, and unresolved spills, identifying whether the Operator or successor in interest will be responsible for any ongoing remediation and reporting responsibilities.

b. An attestation signed by the current Operator and the proposed successor-in-interest will be attached to the Form 9.

c. The Operator will remit with the Form 9 the filing fee provided in Appendix III.

d. If the proposed transfer is subject to a non-disclosure or confidentiality agreement between the Operator and successor in interest, the Operator will indicate on the Form 9 that the proposed transfer is considered confidential, and the Director will keep the Form 9 and any other related information confidential pursuant to § 24-72-204(3)(a)(IV), C.R.S., until the date of transfer listed on the Form 9.

e. The Director will review the Form 9 upon receipt. the Director will approve the Form 9 within 10 business days of when both of the following have occurred:

(1) The Director has determined that the Form 9 is complete and complies with this Rule 218; and

(2) The successor in interest has submitted the financial assurance required by the Commission's Rules.

f. If the Form 9 fails to satisfy Rule 218.a, Rule 218.b., or Rule 218.c, the Director may deny approval of the Form 9 and the current Operator will remain liable for all Oil and Gas Operations under the permits that were proposed for transfer.

g. If an Operator sells a Well, Oil and Gas Location, or related facility without obtaining the Director's approval of a Form 9, the Director may require all such Wells to be shut-in upon the date that the successor in interest assumes ownership of the Wells, Oil and Gas Locations, or related facilities, consistent with the well shut-in safety requirements of Rule 4XX. All such Wells will remain shut-in until a Form 9 is filed and approved by the Director.

h. The Director will not approve a Form 10 Certificate of Clearance for a Well unless there is an approved Form 9.

i. Unless otherwise identified on the Form 9, upon the approval of the Form 9, or the date of transfer identified by Rule 218.a.(1), whichever is later, the successor in interest will assume all liability and reclamation responsibilities of the existing permits from that point forward and will conduct all Oil and Gas Operations in full compliance with the Act, the Commission's Rules, and all terms and conditions of the existing permit.

j. A Form 9 is not required for the transfer of gas gathering systems, gas processing plants, and underground gas storage facilities, which are governed by Rule 220.c.

219. Form 10. CERTIFICATE OF CLEARANCE

a. The Operator of a Well will file with the Director a Form 10, Certificate of Clearance to designate the transporter(s) and gatherer(s), as applicable, for the Well. The certificate, when properly executed and approved by the Commission, constitutes authorization to the pipeline or other transporter to transport the authorized volume from the Well named therein; provided that this section will not prevent the production or transportation in order to prevent waste, pending execution and approval of said certificate.

b. Within 30 days after initial sale of oil or gas, each Operator of a new Well will file a Form 10, Certificate of Clearance with the Director for the Well.

c. The Operator of a Well will file a new Form 10, Certificate of Clearance to change the transporter or gatherer for the Well within 30 days of the change.

(1) In the case of other transporter temporary changes involving the production of less than 1 month, the Operator will notify the Director via a Form 10, indicating the dates of the temporary changes.

(2) In the case of temporary use of oil for well treating or stimulating purposes, a new Form 10 is not required.

d. A new Operator will file a new Form 10 within 30 days of the later of the date a Form 9 is approved or the transfer date identified by Rule 218.a.(1).

e. Operators will pay the filing fee provided in Appendix III when filing a Form 10.

f. The Form 10, Certificate of Clearance, will remain in force and effect until:

(1) The Operator of the Well is changed;

(2) The transporter or gatherer is changed; or

(3) The certificate is revoked by the Commission.

g. It is the Operator's responsibility to provide copies of the approved Form 10, Certificate of Clearance, to the transporter or gatherer for each Well listed.

220. Form 12. GAS FACILITY REGISTRATION/CHANGE OF OPERATOR

a. Facility Registration. The Operator of a new gas gathering system, a new gas compressor station, a new gas processing plant, or a new underground gas storage facility will submit a Form 12, Gas Facility Registration/Change of Operator, within 30 days of placing the new facility into service. The following information must be included:

(1) The name and type of system or facility.

(2) For a gas compressor station or a gas processing plant, the latitude and longitude and the legal location by quarter-quarter, section, township, range, and county.

(3) For a gas gathering system or an underground gas storage facility, latitude and longitude near the center of the system or facility, and a description of the geographic area by section, township, range, and county.

(4) For a gas compressor station, a gas processing plant or an underground gas storage facility, a facility layout drawing.

(5) For a gas gathering system, a geographic area map that clearly shows the gathering line routes, section, township and range lines, waterways, public roadways, county lines, and municipal boundaries.

b. **Annual Reports.** For a gas gathering system, gas processing plant, gas compressor station, or underground storage facility that has had any gathering lines added or removed during the preceding year, the Operator will submit a Form 12 by May 1st of each year to report the changes. For an underground storage facility - that has had an expansion or reduction of its capacity of more than 10% during the preceding year, the Operator will submit a Form 12 by May 1st of each year to report the changes.

c. **Change of Operator**. The previous or new Operator of a gas gathering system, gas compressor station, gas processing plant, or an underground gas storage facility, will submit a Form 12 within 30 days of change of Operator. Documentation confirming transfer of ownership must be attached to the Form 12.

221. PUBLIC HIGHWAYS AND ROADS

All persons subject to the Act and the Commission's Rules are subject to the State Vehicles and Traffic Laws pursuant to Title 42, C.R.S. and the State Highway and Roads Laws, Title 43, C.R.S., pertaining to the use of public highways or roads within the state for Oil and Gas Operations.

222. COGCC Form 18. COMPLAINT REPORT

a. A complaint regarding Oil and Gas Operations is filed by submitting a Form 18.

b. The Director will investigate any complaint and determine what, if any, action will be taken in accordance with Rule 522.

223. CONFIDENTIAL INFORMATION

a. If an Operator or person designates any portion of a document or submission to the Commission as "confidential" and if the document meets the confidentiality provisions of the Colorado Open Records Act, it may be exempt from disclosure to the public, provided that the Operator labels any page with the words "Confidential Information."

b. If information qualifies as confidential under the Colorado Open Records Act, the Commission, the CDPHE, and CPW will keep all such data and information confidential to the extent allowed by the Colorado Open Records Act.

DEFINITIONS
100 SERIES

COMPREHENSIVE AREA PLAN means a plan created by one or more Operator(s) covering future Oil and Gas Operations and addressing cumulative impacts in a defined geographic area.

DIRECTOR'S RECOMMENDATION means the Director's written recommendation to the Commission about whether to approve or deny an Oil and Gas Development Plan pursuant to Rule 305, or whether to approve or deny a Comprehensive Area Plan pursuant to Rule 314.f.

FORMAL CONSULTATION PROCESS means a process for soliciting and receiving meaningful input from the consulting party or parties, with opportunity for in-person meetings to allow for back-and-forth discussion, and a good faith effort to incorporate feedback from the consulting party or parties.

HIGH OCCUPANCY BUILDING UNIT means:

• any School, Nursing Facility as defined in § 25.5-4-103(14), C.R.S., Hospital, Life Care Institutions as defined in § 12-13-101, C.R.S., Correctional Facility as defined in § 17-1-102(1.7), C.R.S., provided the facility or institution regularly serves 50 or more persons;

• an operating Child Care Center as defined in § 26-6-102(1.5), C.R.S.; or

- A multifamily dwelling unit with four or more units.

OIL AND GAS DEVELOPMENT PLAN means a plan to develop oil or gas resources at one or more Oil and Gas Locations, consistent with the requirements of Rule 303.

PROXIMATE LOCAL GOVERNMENT means any Local Government within 2,000 feet of a proposed Oil and Gas Location.

RESIDENTIAL BUILDING UNIT means a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes. Each individual residence within a building will be counted as one Residential Building Unit.

WORKING PAD SURFACE means the portions of an Oil and Gas Location that has an improved surface upon which Oil and Gas Operations take place.

PERMITTING PROCESS
300 SERIES

301. GENERAL REQUIREMENTS FOR APPROVAL, CHANGES TO OPERATIONS, AND FILING FEES FOR OIL AND GAS OPERATIONS.

a. Approval. All operations governed by any regulation in this Series require written approval of the Director or Commission. The Director or Commission will approve operations only if they protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. Operators will obtain the Director's or Commission's approval through the procedures provided in this and such other applicable Commission Rules. The Director or Commission may require any conditions of approval that are determined to be necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources or to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

b. **Denial**. The Director or Commission may deny any Oil and Gas Development Plan or Oil and Gas Operations if:

(1) It does not meet the criteria of this Series; or

(2) It meets the criteria of this Series, but in the Director's or Commissions' judgment does not minimize adverse impacts to and provide necessary and reasonable protections for public health, safety, welfare, the environment, or wildlife resources or it fails to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

c. **Changes to Approved Oil and Gas Development Plans.**

(1) Operators will file any proposed change to an approved Oil and Gas Development Plan with the Director in writing through a Form 4, Sundry Notice. The Form 4 will be posted to the Commission's website at least 14 days prior to resolution of the requested change.

(2) The Director will determine what forms and information are required for the review and approval of the proposed change, and whether:

A. The proposed change is significant and requires Commission approval;

B. The proposed change requires consultation with the CDPHE or CPW; or

C. The proposed change will not alter the basis upon which the Oil and Gas Development Plan is approved and can be administratively approved by the Director.

(3) The Operator will not begin work until the Director or Commission provides written approval.

(4) The Director or Commission will only approve changes that comply with the Commission's Rules.

(5) Notice of a Director approved change to an Oil and Gas Development Plan will be posted to the Commission's website.

d. **Filing Fees.** Operators will pay filing fees at the time of applying for an Oil and Gas Development Plan, Form 2A, Form 2, drilling and spacing unit, or Comprehensive Area Plan (see Appendix III). Wells drilled for stratigraphic information only will be exempt from paying the filing fee.

302. LOCAL GOVERNMENTS.

a. Nothing in the Commission's Rules constrains the legal authority conferred to Local Governments by Colo. Rev. Stat. §§ 29-20-104, 30-15-401, or any other statute, to regulate Oil and Gas Operations in a manner that is more protective or stricter than the Commission's Rules.

b. **Local Government Siting Information.** With their Oil and Gas Development Plans, or, if applicable, with their Form 2A or drilling and spacing unit applications, Operators will submit to the Director certification that:

(1) The Relevant Local Government does not regulate the siting of Oil and Gas Locations.

(2) The Relevant Local Government regulates the siting of Oil and Gas Locations, and the Relevant Local Government has approved the siting of the proposed Oil and Gas Location through a siting process that includes all of the following elements:

i. A formal review and approval process that allows for public comments to be received and considered;

ii. A public hearing on the siting proposal;

iii. An alternative location analysis;

iv. Notice to all persons and entities listed in Rules 303.d.(2) and 303.e.(1);

v. A Formal Consultation Process with the Director and with any Proximate Local Governments;

vi. The proposed Oil and Gas Location complies with Rule 604;

vii. For proposed Oil and Gas Locations within High Priority Habitat, a referral process to CPW.

(3) The Relevant Local Government regulates the siting of Oil and Gas Locations, and has approved the siting of the proposed Oil and Gas Location, but the Relevant Local Government's siting process does not meet all criteria in Rule 302.b.(2).

(4) The Relevant Local Government regulates the siting of Oil and Gas Locations, and has denied the siting of the proposed Oil and Gas Location.

c. Director's Review of Local Government Siting Information.

(1) If the Operator certifies that the Relevant Local Government's siting process meets the criteria provided in Rule 302.b.(1), (3), or (4), then the Director will conduct a siting review consistent with the Commission's Rules.

(2) If the Operator certifies that the Relevant Local Government's siting process meets the criteria provided in Rule 302.b.(2), and the Director agrees, then the Director will defer to the Relevant Local Government's siting disposition.

d. With their Oil and Gas Development Plans, or, if applicable, with their Form 2A, Operators will state whether the proposed Oil and Gas Location is subject to the requirements of § 24-65.1-108, C.R.S. because it is located in an area designated as one of State interest.

e. Notice to Relevant and Proximate Local Governments. An Operator will notify any Relevant and Proximate Local Governments that it plans to submit an Oil and Gas Development Plan no less than 30 days prior to submitting an Oil and Gas Development Plan. The notice will comply with the procedural and substantive requirements of Rule 303.e.(2) & (3).

f. Local Government Waiving Authority.

(1) At any time, a local government may, by providing written notice to the Director and any relevant Operators:

A. Waive its right to receive notice under any or all of the Commission's Rules; or

B. Certify that it chooses not to regulate the siting of Oil and Gas Locations.

(2) The Commission will maintain a list of Local Governments that have certified to the Director that they have chosen not to regulate the siting of Oil and Gas Locations, or receive any category of notice otherwise required by the Commission's Rules.

(3) A Local Government may withdraw a waiver at any time by providing written notice to an Operator and the Director. Upon receiving such notice, the Director will immediately remove the Local Government from the Rule 302.f.(2) list on the Commission's website.

g. Local Government Consultation. At any time after an Operator provides notice of a proposed Oil and Gas Development Plan, and prior to the Director making a Director's Recommendation that the Commission approve or deny the Oil and Gas Development Plan, Relevant Local Governments or Proximate Local Governments may request, and will be provided, an opportunity to consult with the Operator and the Director. The Director or Operator will promptly schedule a Formal Consultation Process meeting. Topics for Formal Consultation Process meeting will include, but not be limited to:

(1) The location of access roads, Production Facilities and wells, and

(2) Necessary and reasonable measures to avoid, minimize, and mitigate adverse impacts to public health, safety, or welfare or the environment, or wildlife resources.

303. PROCEDURAL REQUIREMENTS FOR OIL AND GAS DEVELOPMENT PLANS.

a. Components of an Oil and Gas Development Plan Application. Prior to commencing Oil and Gas Operations an Operator will have an approved Oil and Gas Development Plan. An Operator will submit to the Commission the following:

(1) An application with the Hearings Unit for a hearing on the proposed Oil and Gas Development Plan, pursuant to Rule 503.g.(1). If the Oil and Gas Development Plan includes lands to be spaced, the Oil and Gas Development Plan application will include an application for and request for hearing on the proposed drilling and spacing unit pursuant to Rules 304. and 503.g.(2).

(2) A Form 2A, Oil and Gas Location Assessment ("Form 2A"), that meets all requirements of Rule 303 for each proposed Oil and Gas Location.

(3) Payment of the full filing fee required by Rule 301.d.

(4) Any other information that the Director determines is necessary to determine whether the proposed operation meets the Commission's Rules and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources or that is necessary to ensure the protection against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(5) **Cumulative Impacts Evaluation.** The Operator will provide a narrative, and, if applicable, quantitative evaluation of cumulative impacts to the following resources, and, if applicable, any Best Management Practices it intends to employ to address cumulative impacts on the following resources:

A. Air quality;

B. Water quality;

C. Wildlife;

D. Traffic;

E. Noise;

F. Light;

G. Dust;

H. Odor;

I. Ecosystems, including surface disturbance and soil; and

J. E&P Waste disposal.

(6) A certification that all components of the Oil and Gas Development Plan have been submitted.

b. **Completeness Determination.** After the Operator certifies pursuant to Rule 303.a.(6) that all required components of the Oil and Gas Development Plan have been submitted, the Director will use best efforts to review the application materials within 30 days to determine if they are complete.

(1) If the proposed Oil and Gas Development Plan is complete, the Director will issue a completeness determination to the Operator via electronic mail.

(2) A completeness determination does not constitute approval or denial of an Oil and Gas Development Plan, nor does it convey any rights to conduct any surface-disturbing activities.

(3) At any time, before or after the Director makes a completeness determination, the Director or the Commission may request any information necessary to make a final determination of approval or denial on an Oil and Gas Development Plan. The Operator will provide any requested information before the Commission makes a final decision to approve or deny the Oil and Gas Development Plan.

(4) If the Director determines that an application is incomplete, the Director will notify the Operator of any such inadequacies. The Operator will have 90 days from the date that it was contacted to correct or provide requested information, otherwise all components of the application will be considered withdrawn and the Oil and Gas Development Plan filing fee will not be refunded.

(5) The Director will submit its completeness determination to the Hearings Unit, where it will be part of the record before the Commission on the Oil and Gas Development Plan application.

c. **Revisions to an Oil and Gas Development Plan Application.** At any time prior to the Director making a completeness determination, the Operator may request changes to its Oil and Gas Development Plan or provide additional or different information by contacting the Director. After the Director makes a completeness determination, the Operator may only make material changes to its Oil and Gas Development Plan application with the Director's approval.

d. **Publication of Director's Completeness Determination.**

(1) When the Director makes a completeness determination, the Oil and Gas Development Plan Application components, exemptions granted pursuant to Rule 304.d., and supporting materials will be posted to the Commission's website. The website posting will provide:

A. The date by which public comments must be received to be considered, which is 26 days from the date the Oil and Gas Development Plan was posted; and

B. The mechanism for the public to provide comments.

(2) **Notification for Consultation.** At the same time the Director posts materials to the Commission's website pursuant to Rule 303.d.(1), the Director will provide electronic notice of such posting to:

A. The Local Governmental Designee (LGD) for the Relevant Local Government;

B. The LGD for all Proximate Local Governments, if applicable;

C. CPW, if consultation will occur pursuant to Rule 309.e.; and

D. The CDPHE, if consultation will occur pursuant to Rule 309.f.

(3) **Confidentiality.** If the Operator designates any portion of its Oil and Gas Development Plan application as "confidential" pursuant to Rule 223, and the Director agrees with this designation, then such confidential material will be redacted when the Oil and Gas Development Plan application is posted.

e. **Notice.**

(1) **Who Receives Notice.** The Operator will provide notice of the completeness determination within 5 days to:

A. All owners of minerals to be developed by the Oil and Gas Development Plan.

B. All Surface Owners, Building Unit owners, and residents, including tenants of both residential and commercial properties, within 2,000 feet of any Working Pad Surface included in the Oil and Gas Development Plan. Notice to tenants may be accomplished by sending the notice to the residences addressed to "Current Resident."

C. CPW.

D. The Colorado State Land Board (if a mineral owner).

E. The U.S. Bureau of Land Management (if any federal entity is mineral owner).

F. The Southern Ute Indian Tribe or Ute Mountain Ute Tribe (for applications involving minerals within the exterior boundary of either tribe's reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Tribe).

G. All Schools, Child Care Centers, and School Governing Bodies pursuant to Rule 309.d.

H. Police, fire departments, emergency service agencies, and first responder agencies responsible for ensuring public safety in all areas within 2,000 feet of any Working Pad Surface included in the Oil and Gas Development Plan.

(2) **Substance of Notice.** Notice provided by the Operator pursuant to this section will include:

A. An introductory letter including:

i. The Operator's contact information including its electronic mail address, phone number, and physical address(es) to which the public may direct questions and comments;

ii. The contact information for the Local Governmental Designee of the Relevant Local Government, if applicable;

iii. The Commission's website address and main telephone number;

iv. The location of all proposed Oil and Gas Locations; and

v. The anticipated date that each phase of operations will commence (by month and year).

B. A description of the proposed Oil and Gas Development Plan, including:

i. How many wells and locations are proposed;

ii. The proposed construction schedule by quarter and year;

iii. A description of each operational phase of development and what to expect during each phase; and

iv. Proposed haul routes and traffic volume associated with each phase of operations.

C. An explanation of the procedural steps involved with the Director's and Commission's review of Oil and Gas Development Plans;

D. An explanation of the Commission's public comment process and the relevant deadlines;

E. The COGCC's information sheet about Hydraulic Fracturing Treatments unless Hydraulic Fracturing Treatments will not be utilized at any Well within the proposed Oil and Gas Development Plan;

F. Other information that the Director may determine may be in the interest of public health, safety, welfare, the environment, or wildlife resources that the Director requires to be included;

G. Information about how the public may view the status of the proposed Oil and Gas Development Plan application on the Commission's website; and

H. Information on how the public may learn more details about and ask questions about the Oil and Gas Development Plan prior to the closure of the public comment period.

(3) Procedure for Providing Notice. Notice will be delivered by one of the following mechanisms:

A. Hand delivery, with confirmation of receipt;

B. Certified mail, return-receipt requested;

C. Electronic mail, with electronic receipt confirmation; or

D. By other delivery service with receipt confirmation.

f. **Publication of Comments.** The Director will post public comments on the Commission's website according to applicable guidance.

g. **Extension of Comment Period.** The Director may extend the comment period by any duration it determines to be reasonable in order to obtain public input.

h. **Drilling and Spacing Unit Applications.** When an Oil and Gas Development Plan includes a drilling and spacing unit, it will be noticed and subject to the petition process set forth in Rules 504.b.(2) and 510.

304. FORM 2A: OIL AND GAS LOCATION ASSESSMENT APPLICATION.

a. Operators will submit a completed Form 2A, Oil and Gas Location Assessment as part of their Oil and Gas Development Plan application, as required by Rule 303.a.(1). Operators will submit and obtain approval of a Form 2A prior to:

(1) Surface disturbance at a site previously undisturbed by Oil and Gas Operations;

(2) Surface disturbance for purposes of expanding or modifying an existing Working Pad Surface or Oil and Gas Location; or

(3) Any significant change to the design and operation of an Oil and Gas Location, including but not limited to the addition of a Well or a Pit, except an Emergency Pit or a lined Plugging Pit. A Form 2A may not be required if significant changes at an existing Oil and Gas Location are made in response to new requirements or regulations from other State or Federal Agencies or the Relevant Local Government.

b. **Information Requirements.** All Form 2A, Oil and Gas Location Assessments Applications must include the following information:

(1) Local Government Siting Information. The Operator will comply with the certification requirements of Rule 303.a.(6).

(2) Alternative Location Analysis.

A. **Applicability:** This Rule 304.b.(2) applies to any proposed Oil and Gas Location that does not meet the criteria of 302.b.(2), and meets one or more of the following criteria:

i. The proposed Oil and Gas Location is within 1,500 feet of 10 or more Building Units;

ii. The proposed Oil and Gas Location is within a Floodplain;

iii. At the time the Form 2A is submitted, the proposed Oil and Gas Location is subject to a Surface Owner protection bond under Rule 703;

iv. **[Placeholder for High Priority Habitat]**; or

v. The Director determines that an alternative location analysis is necessary to protect public health, safety, welfare, the environment, or wildlife resources.

B. If an alternative location analysis is required, the Operator will prepare an analysis for the Commission that identifies all potential alternate locations that may be considered for siting of the Oil and Gas Location. The analysis will address why siting of the Oil and Gas Location at each of the alternative locations is or is not more protective of public health, safety, welfare, the environment, and wildlife resources.

C. The Director may request that the Operator analyze additional locations for the Oil and Gas Location if the Director believes that other locations may be more protective of public health, safety, welfare, the environment, and wildlife resources than any of locations the Operator initially analyzed.

(3) Cultural Distances.

A. A table showing the distance and approximate bearing from the edge of the Working Pad Surface of the proposed or existing Oil and Gas Location to the edge or corner of the nearest building, Residential Building Unit, High Occupancy Building Unit, and School Facility; the nearest boundary of a Designated Outside Activity Area; and the nearest public road, above ground utility, railroad, and property line.

B. A table showing the number of buildings, Residential Building Units, High Occupancy Building Units, School Properties, School Facilities, and Designated Outdoor Activity Areas within the following radii of the Working Pad Surface:

i. 0-500 feet

ii. 501-1,000 feet

iii. 1,001-2,000 feet

C. A current aerial image depicting the information in the tables in Rules 304.b.(3).A & B.

(4) Location Pictures. The Operator will attach to the Form 2A photographs as described below. The photographs will depict the staked location and its surroundings. Each photograph will be identified by: date taken, Well or location name, and direction of view. The field of view of each photograph will be shown on a current aerial image, also attached. Operators will provide location photographs in sufficiently high resolution so that details of current surrounding land use may be readily discerned. Operators will attach one of the following photograph options:

A. A minimum of 4 color photographs, 1 of the staked location and its surroundings from each cardinal direction, with no significant gaps between fields of view;

B. A minimum of 2 panoramic photographs of the location and its surroundings covering a full 360° around the location; or

C. Photographs of the locations and its surroundings taken from an unmanned aerial vehicle.

(5) Site Equipment List. A list of major equipment components to be used in conjunction with drilling and operating the Well(s), including but not limited to, all Tanks, Pits, flares, combustion equipment, separators, and other ancillary equipment.

(6) Pipeline Descriptions. A description of the location, size, and material of any Pipelines for oil, gas, or water, including all Pipelines referenced in the Gas Capture Plans submitted pursuant to Rule 913.f.(1).B.

(7) Drawings. Operators will provide the drawings, maps and figures required below in a suitable size, scale, and electronic format for the Director to conduct a review. If multiple drawings are required to convey the required information, then the Operator will provide them in a logical manner. All drawings, maps, and figures will include a scale bar and north arrow, the Operator's name, the site name, and other information as necessary to identify the attachment as part of the Oil and Gas Development Plan. Aerial imagery used for base maps will be current.

A. Location Drawings. A scaled drawing and scaled aerial photograph showing the approximate outline of the Oil and Gas Location and Working Pad Surface and all visible improvements within 2,000 feet of the proposed Oil and Gas Location (as measured from the proposed edge of the Working Pad Surface), with a horizontal distance and approximate bearing from the Working Pad Surface. If there are no visible improvements within 2,000 feet of a proposed Oil and Gas Location, the Operator will specify this on the Form 2A. Visible improvements will include, but not be limited to:

i. All buildings and Building Units, with High Occupancy Building Units identified;

ii. Publicly maintained roads and trails, including their names;

iii. Fences;

iv. Above-ground utility lines;

v. Railroads;

vi. Pipelines or Pipeline markers;

vii. Mines;

viii. Oil and gas Wells and associated Production Facilities;

ix. Injection wells and associated facilities;

x. Plugged oil and gas wells, including dry holes;

xi. Known water wells; and

xii. Known sewers with manholes.

B. Layout Drawings. Location construction and operations layout drawings, location construction and operations cross-section plots including location and finish grades, and operations facility layout drawings. These drawings will include, as applicable to the proposed Oil and Gas Location, the:

i. The Working Pad Surface and surrounding disturbed area making up the entirety of the Oil and Gas Location;

ii. Drill rig layout;

iii. Well completion and stimulation, including Hydraulic Fracturing Treatment, layout;

iv. If a Well is proposed to be hydraulically fractured, a layout drawing of the flowback equipment, including the equipment and connections to comply with green completion requirements; and

v. The location of all existing and proposed Oil and Gas Facilities listed on the Form 2A.

C. Wildlife Habitat Drawing. A drawing, map, or aerial image depicting High Priority Habitat within 1 mile of the Working Pad Surface.

D. Process Flow Diagrams. Process flow diagrams depicting:

i. Flowback operations; and

ii. Oil and gas production operations.

E. Hydrology Map. A topographic map showing the horizontal distance and approximate bearing from the Oil and Gas Location to:

i. All Waters of the State within 2,640 feet of the proposed Working Pad Surface. The map will indicate which surface water features are downgradient;

ii. All Water Sources within 2,640 feet of the proposed Working Pad Surface;

iii. Any Public Water System intakes within 2,640 feet of the Working Pad Surface;

iv. Rule 408 Table 1 buffer zones within 2,640 feet of the Working Pad Surface; and

v. Any surface waters within 2,640 feet of the Working Pad Surface that are 15 stream miles upstream of a Public Water System intake.

F. Access Road Map. A U.S. Geological Survey topographic map, or scaled aerial photograph showing the access route from the nearest publicly-maintained road to the proposed Oil and Gas Location, and identifying any new access roads constructed as part of the Oil and Gas Development Plan.

G. Related Location and Pipeline Map. A U.S. Geological Survey topographic map, or scaled aerial photograph showing:

i. All existing, approved, and proposed Oil and Gas Locations within 2,000 feet of the area affected by the proposed Oil and Gas Development Plan;

ii. All proposed Pipeline and Flowline corridors to or from the proposed Oil and Gas Location and to or from associated Oil and Gas Facilities.

H. Well Plan Map. If the proposed Oil and Gas Location includes one or more directional Wells, a map showing the surface hole location and the proposed wellbore trajectory with the top of the productive zone and bottom-hole location for each Well.

(8) Geographic Information System (GIS) Data. GIS polygon data to describe the boundaries of the entire proposed Oil and Gas Location and the Working Pad Surface.

(9) Land Use Description. A narrative description of the current land use(s), and the landowner's designated final land use(s) for the purpose of determining reclamation standards.

A. If the final land use includes residential, industrial/commercial, or cropland and does not include any other uses, the land use should be indicated and no further information is needed.

B. If the final land use includes rangeland, forestry, recreation, or wildlife habitat, then a Reference Area will be selected and documented. The Operator will also submit the following information:

i. **Reference Area Map.** A topographic map or aerial image showing the location of the Reference Area with respect to the proposed Oil and Gas Location including latitude and longitude of Reference Area ; and

ii. **Reference Area Pictures.** 5 color photographs of the Reference Area, 4 taken from each cardinal direction, and 1 taken from above the Reference Area. Each photograph will be identified by date taken, Well or Oil and Gas Location name, and direction of view. The photographs will be taken during the peak growing season and must clearly depict vegetation cover and diversity. To ensure that the photographs accurately depict vegetation during peak growing season, these photographs may be submitted up to 12 months after the Form 2A. Photographs of the Reference Area may be taken from an unmanned aerial vehicle, provided such aerial images are collected at a sufficient resolution to provide specific vegetation information.

iii. A table of the dominant vegetation within the Reference Area.

(10) **NRCS Map Unit Description.** A Natural Resources Conservation Service (NRCS) soil map unit description.

(11) **Best Management Practices.** A description of any Operator-proposed, site specific Best Management Practices that the Operator commits to perform as part of the implementation of the Oil and Gas Development Plan.

(12) **Surface Owner Information.**

A. Contact information for the Surface Owner(s); and

B. A redacted version of the Surface Use Agreement or a memorandum describing the Surface Use Agreement that includes a description of the lands subject to the agreement, signatures of the parties to the agreement, dates of signature, and any provisions of the agreement that are relevant to the Form 2A.

(13) **Proximate Local Government Information.** Contact information for any Proximate Local Governments.

(14) **Public Water Systems Protections.** If the proposed Working Pad Surface is within a zone defined in Rule 411, Table 1 or within 2,640 feet of surface water that is within 15 stream miles upstream from a Public Water System intake point, the Operator will provide a copy of the CDPHE's Public Water Systems Supply Area Map and will certify that it has provided notification of the application submittal to potentially impacted Public Water Systems within 15 stream miles downstream, and that it maintains an emergency spill response program as required by Rule 408.b.(1).B.

(15) **Wetlands.** If a permit is required for the discharge of dredged or fill material during the construction of a proposed Oil and Gas Location, access roads to the Oil and Gas Location or Pipeline corridors associated with the Oil and Gas Location, evidence that the Operator has sought such a permit and whether the permit has been issued. The Director may request a third party to confirm an Operator's claim that such a permit is not required. The Director will not approve a Form 2A, Oil and Gas Location Assessment until the Operator has obtained all required discharge permits.

(16) Schools and Child Care Centers. If the proposed Oil and Gas Location is within 2,000 feet of a potential School Facility or Child Care Center, a statement indicating whether the School Governing Body requested consultation.

(17) Water Plan. A plan identifying the planned source of water for drilling and completion operations including:

A. The planned source of all surface water and Groundwater to be used and the coordinates of the planned source of water;

B. The seller's name and address if water is to be purchased;

C. Percentages of the water to be used that will be fresh water, recycled, or reused water; and

D. If recycled or reused water is anticipated to be used, describe the source of that water and anticipated volumes to be used in addition to the reuse and recycling plan requirements of Rule 905.a(3).

(18) Agriculture. An analysis of impacts to agriculture, including both crop farming and livestock grazing, if applicable.

A. One or more detailed maps showing characteristics of known Groundwater within the proposed CAP's boundaries, including but not limited to depth of the water table, depths of known Groundwater formations, and characteristics of the Groundwater including salinity.

c. Plans. All Form 2A, Oil and Gas Location Assessments Applications will include site specific plans that demonstrate compliance with the Commission's Rules for the operation of the proposed Oil and Gas Location in a manner that is protective of public health, safety, welfare, the environment, and wildlife resources. Each Form 2A, Oil and Gas Location Assessment Application will include the following plans:

(1) Emergency Spill Response Program. For operations within 2,640 feet of surface water that is 15 miles or less upstream from a Public Water System(s) intake, an emergency spill response program consistent with the requirements of Rule 408.b.(1).A.

(2) Noise Mitigation Plan. A noise mitigation plan consistent with the requirements of Rule 440.a.

(3) Light Mitigation Plan. A light mitigation plan consistent with the requirements of Rule 441.a.

(4) Odor Mitigation Plan. An odor mitigation plan consistent with the requirements of Rule 443.a.

(5) Dust Mitigation Plan. A dust mitigation plan consistent with the requirements of Rule 444.a.

(6) Transportation Plan. If the Relevant Local Government requires a transportation plan or an equivalent traffic planning document, the transportation plan submitted to the Relevant Local Government. If the Relevant Local Government does not require a transportation plan, the Director may request information regarding haul routes, traffic volumes, and Best Management Practices to avoid, mitigate, and minimize impacts from traffic associated with the Oil and Gas Location.

(7) **Process Safety Management Program.** A process safety management program consistent with the requirements of Rule 601.d.

(8) **Emergency Response Plan.** An emergency response plan consistent with the requirements of Rule 603.e.(18).

(9) **Flood Shut-In Plan**. If located in a floodplain, a shut-in plan consistent with the requirements of Rule 608.b.(2).

(10) **Hydrogen Sulfide Drilling Plan.** If operating in zones known or suspected to contain at or above 100 parts per million hydrogen sulfide gas, a hydrogen sulfide drilling plan consistent with the requirements of Rule 612.a.

(11) **Waste Management Plan.** A waste management plan consistent with Rule 907.a.(4).

(12) **Gas Capture Plan.** A gas capture plan consistent with the requirements of Rule 913.f.(1).B.

(13) **Fluid Leak Detection Plan.** A fluid leak detection plan consistent with the requirements of Rule 914.

(14) **Topsoil Protection Plan.** A topsoil protection plan consistent with the requirements of Rule 1002.c.

(15) **Stormwater Management Plan.** A stormwater management plan consistent with the requirements of Rule 1002.f.

(16) **Interim Reclamation Plan.** An interim reclamation plan consistent with the requirements of Rule 1003.

(17) **Wildlife Protection Plan.** If the proposed Oil and Gas Location is located within High Priority Habitat, a wildlife protection plan consistent with the requirements of the Commission's 1200 Series Rules.

d. **Lesser Impact Areas.** The Director may exempt an Operator from submitting any of the information required by Rule 304.b., or any plan required by Rule 304.c., under the following circumstances:

(1) If the Operator requests an exemption from the Director based on evidence showing the information or plan is unnecessary because:

A. The impacted resource or resource concern are not present in the area; or

B. Impacts to the resource will be so minimal as to pose no concern.

(2) Operators may request an exemption from the Director in writing, without proceeding through the ordinary Rule 502.a. variance process. A request for an exemption will be provided with the Form 2A at the time the Form is submitted.

(3) The Director may grant an exemption as part of the completeness determination if the Director concurs that the Operator providing the information or plan is unnecessary to minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources and will protect against adverse environmental impacts on any air, water, soil, or biological resource.

(4) If the Director grants an exemption, the Commission may nevertheless request the information or plan subject to the exemption, or related information, if the Commission determines that reviewing the information or plan is necessary to protect and minimize adverse impacts.

305. APPLICATION FOR A DRILLING AND SPACING UNIT.

a. Procedural Requirements.

(1) Operators seeking to create a new drilling and spacing unit, or to modify an existing drilling and spacing unit, will file a drilling and spacing unit pursuant to Rule 503.g.(2). If the proposed drilling and spacing unit is part of an Oil and Gas Development Plan application, the drilling and spacing unit application will be included with the hearing application for that Oil and Gas Development Plan.

(2) All drilling and spacing unit applications will include the following information:

A. Certification that the Operator has complied with the local government siting disposition requirements of Rule 302.b.

B. Certification that the operations in the drilling and spacing unit will be conducted in a reasonable manner to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources and will protect against adverse environmental impacts on any air, water, soil, or biological resource.

C. The unit boundary and interwell setback distances.

D. All existing Oil and Gas Locations and associated Wells that are developing the same formation in the application lands. The application will discuss what the Operator intends to do with the existing Oil and Gas Locations and Wells.

E. The wellbore orientation for all horizontal wells in the proposed unit.

F. Whether there are existing units and Wells within the proposed application lands and what the disposition of those existing units and Wells in those existing units will be under the proposed application.

G. The Oil and Gas Locations that are proposed for the unit. If an Operator has applied for a Form 2A, the Operator will identify its document number. If the Form 2A has already been approved, the Operator will identify its Location ID number.

H. The total number of proposed Wells for the unit.

I. Any additional information as may be required to support the requested prayer for relief.

J. All prior orders that implicate the prayer for relief.

K. Certification that satisfies the requirements of Rule 505.a.(1).

b. Standards for Approval. In determining whether to recommend that the Commission approve or deny a proposed drilling and spacing unit, the Director will consider whether the proposed drilling and spacing unit:

(1) Protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations;

(2) Prevents waste of oil and gas resources;

(3) Avoids the drilling of unnecessary Wells; and

(4) Protects correlative rights.

306. Director's Recommendation on the Oil and Gas Development Plan.

a. When the Director May Issue a Recommendation. The Director will not make a recommendation to the Commission about whether to approve or deny any Oil and Gas Development Plan until after:

(1) The Director has fully reviewed the Oil and Gas Development Plan and all supporting application materials and has obtained all information necessary to evaluate the proposed operation and its potential impacts on public health, safety, welfare, the environment and wildlife resources;

(2) The Director has reviewed and commented on the drilling and spacing unit application, if submitted with the Oil and Gas Development Plan;

(3) The public comment period has ended and the Director has considered all substantive public comments received, including comments from the Relevant Local Government or Proximate Local Government;

(4) If applicable, CPW and the CDPHE consultations have been completed and submitted to the Director; and

(5) The Director determines that the Operator has provided adequate Financial Assurance as required by the 700 Series Rules for both the proposed Oil and Gas Development Plan and all existing facilities owned by the Operator.

b. Director's Recommendation.

(1) **Approval.** The Director may recommend that the Commission approve an Oil and Gas Development Plan that:

A. Complies with all requirements of the Commission's Rules; and

B. In the Director's judgment, protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. The Director may recommend that the Commission add conditions to the approval that are necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources and to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(2) **Denial.** If the Director determines that an application does not provide necessary and reasonable protections for public health, safety, welfare, the environment, and wildlife resources or fails to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations, or fails to meet the requirements of the Commission's Rules, the Director may recommend that the Commission deny the Oil and Gas Development Plan.

c. Notice of Recommended Decision. Upon making a recommendation that the Commission approve or deny an Oil and Gas Development Plan, the Director will post the written basis for the Director's Recommendation on the Commission's website, file its recommendation with the Hearings Unit, and notify the following persons electronically in a manner determined by the Director:

(1) The Surface Owner;

(2) The Operator;

(3) The Relevant Local Government;

(4) All Proximate Local Governments;

(5) The CDPHE, if consultation occurred subject to Rule 309.f.;

(6) CPW, if consultation occurred subject to Rule 309.e.;

(7) The Colorado State Land Board (if a mineral owner); and

(8) The appropriate federal agency (if any federal entity is mineral owner).

307. COMMISSION CONSIDERATION OF THE OIL AND GAS DEVELOPMENT PLAN.

a. Director's Recommendation. Upon receipt of the Director's Recommendation on an Oil and Gas Development Plan, it will be considered by the Commission in accordance with Rule 510 and Rules 508 and 509, as appropriate. The Commission will consider whether to delegate consideration of an Oil and Gas Development Plan to an Administrative Law Judge or Hearing Officer.

b. Commission's Consideration of Director's Recommendation.

(1) **Approval.** The Commission may approve an Oil and Gas Development Plan that complies with all requirements of the Commission's Rules, and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. The Commission may add any conditions to the approval of an Oil and Gas Development Plan that it determines are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect public health, safety, welfare, the environment, and wildlife resources or to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(2) **Denial.** If the Commission determines that an Oil and Gas Development Plan does not provide necessary and reasonable protections for public health, safety, welfare, the environment, and wildlife resources, or that it fails to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations or fails to meet the requirements of the Commission's Rules, the Commission may deny the Oil and Gas Development Plan. The Commission will identify in the record the basis for the denial.

(3) **Stay.** If the Commission determines that additional information or analysis is necessary for it to make a decision to approve or deny an Oil and Gas Development Plan, it may stay consideration of the Oil and Gas Development Plan for further consideration until the

Director or Operator can provide the Commission with the additional information or analysis necessary to consider the Oil and Gas Development Plan.

c. Final Agency Action. The Commission's decision to approve or deny an Oil and Gas Development Plan will constitute final agency action. The Commission's decision to stay an Oil and Gas Development Plan for further consideration will not constitute final agency action.

308. FORM 2: APPLICATION TO DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE AND OPERATE.

a. Submitting Form 2. If the Commission approves an Operator's Oil and Gas Development Plan, or if the Operator's Form 2A was approved prior to the effective date of this Rule, then the Operator will submit and obtain the Director's approval of a complete Form 2 before taking any of the actions listed in Rule 308.a.(1)–(6) below. The Form 2 will detail the Operator's plans to:

(1) Drill any Well;

(2) Deepen any existing Well;

(3) Re-enter any plugged Well (except for re-entry to re-plug will require a Well Abandonment Report, Form 6, per Rule 426);

(4) Recomplete and operate any existing Well;

(5) Drill a sidetrack from any Well; or

(6) Convert a stratigraphic Well into a production Well.

b. Information Requirements. All Form 2 applications require the following information:

[This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking, Docket No. 191200754.]

(1) Every Form 2, Application for Permit-to-Drill will specify the distance between the Well and wall or corner of the nearest building, Building Unit, High Occupancy Building Unit, Designated Outside Activity Area, public road, above ground utility, railroad, and property line.

(2) **Wellbore Diagram.** A Form 2 to deepen, to re-enter, to recomplete to a different reservoir, or to drill a sidetrack of an existing Well will have a wellbore diagram attached.

(3) A Form 2 to deepen, to re-enter, to recomplete to a different reservoir, or to drill a sidetrack of an existing Well will include the details of the proposed work.

(4) **Well Location Plat.** A Form 2 to drill a new Well or a new wellbore will have a well location plat attached. The plat will be a current scaled drawing(s) of the entire section(s) penetrated by the proposed Well with the following minimum information:

A. Dimensions on adjacent exterior section lines sufficient to completely describe the quarter section(s) containing the proposed Well surface location, top of productive zone, wellbore, and bottom hole location will be indicated. If dimensions are not field measured, the plat will state how the dimensions were determined.

B. For irregular, partial or truncated sections, dimensions will be furnished to completely describe the entire section(s) containing the proposed Well.

C. The field-measured distances from the nearer north/south and nearer east/west section lines will be measured at 90 degrees from said section lines to the Well surface location and referenced on the plat. For unsurveyed land grants and other areas where an official public land survey system does not exist, the Well locations will be spotted as footages on a protracted section plat using Global Positioning System (GPS) technology and reported as latitude and longitude in accordance with Rule 215.

D. The latitude and longitude of the proposed surface location will be provided on the drawing with a minimum of 5 decimal places of accuracy and precision using the North American Datum (NAD) of 1983 (e.g. latitude 37.12345 N, longitude 104.45632 W). If GPS technology is utilized to determine the latitude and longitude, all GPS data shall meet the requirements set forth in Rule 215.

E. The Well location plat will include the proposed top of the productive zone and the bottom hole location. If the wellbore penetrates multiple sections, the Well location plat will depict every section penetrated by the wellbore.

F. A map legend.

G. A north arrow.

H. A scale expressed as an equivalent (e.g. 1 inch = 1000 feet).

I. A bar scale.

J. The ground elevation.

K. The basis of the elevation (how it was calculated or its source).

L. The basis of bearing or interior angles used.

M. Complete description of monuments and collateral evidence found; all aliquot corners used will be described.

N. The legal land description by section, township, range, principal meridian, baseline, and county.

O. Operator name.

P. Well name and Well number.

Q. Date of completion of scaled drawing.

(5) **Deviated Drilling Plan.** A Form 2 to drill a deviated (directional, highly deviated, or horizontal) wellbore utilizing controlled directional drilling methods will have the deviated drilling plan attached. The deviated drilling plan will meet the requirements set forth in Rule 410.

(6) **Casing and Cementing Plan.** A Form 2 to drill a Well will include a casing and cementing plan that addresses anticipated Groundwater by demonstrating how it will be isolated, potential flow and hydrocarbon bearing zones, and subsurface hazards.

(7) **Statewide Offset Well Evaluation**.

A. The Form 2 will include an offset Well evaluation. The Operator will evaluate the construction and integrity of all offset Wells within 1,500 feet of the proposed wellbore. The Operator will provide a plan to address all offset Wells within 1,500 feet that do not meet isolation and integrity requirements.

B. The Operator will attach any consents obtained pursuant to Rule 408.u. to the Form 2.

C. The Operator will provide notice as required by Rule 408.v.

(8) **Hydraulic Fracturing Treatment at Depths 2,000 Feet or Less.** If an Operator proposes to drill a Well at a depth less than 2,000 feet true vertical depth (TVD) below the surface that will be subject to Hydraulic Fracturing Treatment, the following requirements apply:

A. **Geology and Hydrogeology Assessment.** The Operator will characterize and assess the local geology and Groundwater resources within 2 miles of the proposed oil and gas Well.

B. **Engineering Assessment.** The Operator will describe the proposed drilling process, Well design, completion process, Hydraulic Fracturing Treatment process, production methods, and facilities. The assessment will identify any risks to geology and hydrogeology and explain how the Operator will prevent, minimize, or mitigate any identified risk.

[The changes proposed in sections 1-8 above are under consideration in the Wellbore Integrity rulemaking Docket No. 191200754.]

(9) **Drilling and Completion Plan.** A drilling and completion plan will include information about the proposed operation and objective formation(s), including, but not limited to how the Well is to be drilled, cased, cemented, perforated, stimulated, plumbed to the permanent equipment and other relevant information to understand the operations.

A. The location, orientation, and extent of any known or suspected faults, fractures, and existing or abandoned oil, gas, or water wells within one mile (horizontal distance) of the wellbore trajectory.

B. The drilling and deviated drilling plan must be attached and meet the requirements set forth in Rule 407.a. The Well Location Plat required by Rule 308.b.(4) must show the Well's plan view path through all penetrated sections and the also meet the requirements of Rule 407.a.

c. Administrative Approval or Denial of the Form 2.

(1) The Director may approve a Form 2 that complies with all requirements of the Commission's Rules, and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. The Director may add any conditions of the approval to a Form 2 that are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect public health, safety, welfare, the environment and wildlife resources or to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(2) The Director may deny any Form 2 that does not meet all requirements of the Commission's Rules, or that does not provide necessary and reasonable protections for public health, safety, welfare, the environment, and wildlife resources, or that fails to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. The Director will put forth the reason for the denial. If the Director denies a Form 2, the Operator has the right for a hearing in front of the Commission at an upcoming hearing.

(3) The Director may request, and an Operator will provide upon request, any information necessary to determine whether to approve or deny a Form 2.

d. Changes to Form 2. Prior to approval of the Form 2 permit application, minor revisions or requested information may be provided by contacting the COGCC staff. After approval, any substantive changes will be submitted for approval on a Form 2. A Form 4, Sundry Notice will be submitted, along with supplemental information requested by the Director, when non-substantive revisions are made after approval, and no additional fee will be imposed.

309. CONSULTATION.

a. All consultations required by Rule 309 will occur within 45 days after the Director posts the completeness determination on the Commission's website pursuant to Rule 303.d.(1).

b. Surface Owners. The Operator will consult in good faith with the Surface Owner, or the Surface Owner's appointed agent about the location of all surface disturbance, and in preparation for reclamation and abandonment. The Surface Owner or appointed agent may submit relevant comments to the Director about any Oil and Gas Development Plan pursuant to Rule 303.d.(1).

(1) **Information Provided by Operator.** When consulting with the Surface Owner or appointed agent, the Operator will furnish, in writing:

A. All the information required for a complete Oil and Gas Development Plan;

B. The expected date of commencement of operations;

C. Topsoil management practices to be employed; and

D. The location of associated roads, Production Facilities, infrastructure, and any other areas to be used for Oil and Gas Operations.

(2) **Waiver.** The Surface Owner or the Surface Owner's appointed agent may waive, permanently or otherwise, their right to consult with the Operator at any time. Such waiver must be in writing, signed by the Surface Owner, and submitted to the Operator and Director.

(3) Operators will conduct Oil and Gas Operations in a manner that accommodates the Surface Owner by minimizing intrusion upon and damage to the surface of the land.

c. Building Unit Owners and Tenants. An Operator will be available to meet with residents (including owners and tenants) of Building Units located within 2,000 feet of the proposed Working Pad Surface. Building Unit Owners, their agents, their tenants, or a Local Government may request such a meeting.

(1) **Information provided by Operator.** When meeting with Building Unit owners or their appointed agent(s) or tenants, the Operator will provide the following information:

A. The date construction is anticipated to begin;

B. The anticipated duration of pad construction, drilling and completion activities;

C. The types of equipment anticipated to be present on the proposed Oil and Gas Locations;

D. The Operator's interim and final reclamation obligation;

E. A description and diagram of the proposed Oil and Gas Locations that includes the dimensions of the proposed Oil and Gas Location and the anticipated layout of production or injection facilities, Pipelines, roads and any other areas to be used for Oil and Gas Operations;

F. Information relevant to potential health, safety, welfare, and environmental impacts associated with Oil and Gas Operations, including but not limited to security, noise, light, odors, dust, and traffic; and

G. Information about proposed Best Management Practices or mitigation measures to avoid, minimize or mitigate those issues.

(2) **Waiver.** The Building Unit owner, agent or tenant may waive, permanently or otherwise, their respective right to receive notice pursuant to the Commission's Rules. Any such waiver will be in writing, signed by the owner, agent or tenant, and will be submitted by the Building Unit owner, agent, or tenant to the Operator and the Director.

(3) Operators and the Director will consider all concerns related to public health, safety, welfare, the environment, and wildlife resources raised by Building Unit owners, their agents or tenants during informational meetings or in written comments.

d. Schools, Child Care Centers, and School Governing Bodies.

(1) No less than 30 days before the Operator submits an Oil and Gas Development Plan, an Operator will provide a pre-application notice of intent to conduct Oil and Gas Operations to any relevant School, Child Care Center, and School Governing Body within 2,000 feet of:

A. The property line of a parcel currently owned by the School, Child Care Center, or School Governing Body as identified through county assessor records;

B. The property line of a parcel considered a Future School Facility as identified on the final approved plat that may be obtained from the planning department of the Relevant Local Government; or

C. What reasonably appears to be a School Facility (regardless of property ownership) based on the Operator's review of current aerial maps that show surface development or surveys of the area.

(2) The Notice will include:

A. The Operator's contact information;

B. The location and general description of the proposed Oil and Gas Location, including the Cultural Distances table as required under Rule 304.b.(3).B., and drawings, maps, and figures required under Rule 304.b.(7).

C. The Local Governmental Designee's (LGD) contact information, if applicable;

D. The anticipated date, by calendar year and quarter, that construction will begin and the expected schedule of drilling and completion activities;

E. A description of the status of the Relevant Local Government's siting disposition, if applicable;

F. Notice that the School Governing Body for the School Facility or Child Care Center may request a consultation to discuss the proposed operations by contacting the Operator, and that the Director may be invited to any meeting. A School Governing Body or Child Care Center may delegate the consultation process to the principal or senior administrator of a School or Child Care Center in proximity to the proposed Oil and Gas Location; and

G. Notice that the School, Child Care Center, or School Governing Body may submit comments regarding the proposed Oil and Gas Location to the Commission as part of the Rule 303.d.(1) public comment period.

(3) A School Governing Body may waive the right to receive notice under this provision for it and all schools within the area subject to the School Governing Body's oversight at any time by providing written notice to the Operator and the Director.

(4) The Operator, School Governing Body, or Director may initiate consultation pursuant to this Rule. During the consultation, the School Governing Body may identify additional discrete facilities or areas it considers a School Facility or Child Care Center, and the Operator will provide relevant information regarding planned measures to avoid, minimize, or mitigate adverse impacts to the School Facility or Child Care Center.

e. CPW. [HOLD]

f. Consultation with the CDPHE.

(1) When Consultation Must Occur.

A. The Director will consult with the CDPHE if:

i. At any time during the local government consultation and comment period, a Local Government requests the participation of the CDPHE in the Director's consideration of an Oil and Gas Development Plan or Comprehensive Area Plan based on concerns regarding public health, safety, welfare, or impacts to the environment; or

ii. An Operator requests a variance from the Director from a provision of any Rule intended to protect public health, safety, welfare, or the environment.

B. The Director will consult with the CDPHE when an Operator requests a modification of an existing Commission order to increase Well density or otherwise proposes a Well density of more than 1 Well per 40 acres.

C. The Director will consult with the CDPHE when the Commission develops a regulation that can reasonably be anticipated to have impacts on public health, welfare, safety, or the environment.

D. The Director may request consultation about any Oil and Gas Development Plan or Comprehensive Area Plan if the Director reasonably believes that consultation with the CDPHE would assist the Director in understanding the potential risks to public health, safety, welfare, or the environment.

E. The Director will consult with the CDPHE if the CDPHE requests consultation.

F. Notwithstanding the foregoing, the requirement to consult with the CDPHE may be waived by the CDPHE at any time.

(2) Procedure for Consultation.

A. The Director and the CDPHE will have 45 days to conduct the consultation required by this section. The time period for consultation will begin at the start of the Rule 303.d.(1) public comment period. If the public comment period is extended by the Director or the Commission, then the 45 day consultation period may also be extended for the same amount of time that the public comment period is extended. Following conclusion of the initial consultation period, the Director may reopen consultation with the CDPHE if information pertaining to the Oil and Gas Development Plan or Comprehensive Area Plan changes or new evidence arises related to the public health or environmental impacts of the Oil and Gas Development Plan or Comprehensive Area Plan.

B. The consultation required by this section will focus on identifying potential impacts to public health, safety, welfare, or the environment from activities associated with the proposed Oil and Gas Development Plan or Comprehensive Area Plan, and development of conditions of approval or other measures to avoid, minimize, or mitigate those potential adverse impacts.

C. The Consultation process may include, but is not limited to:

i. Review of the relevant Oil and Gas Development Plan or Comprehensive Area Plan application, variance request, Well-density application, or draft Commission regulation;

ii. Discussions with the Relevant Local Governments and Proximate Local Governments to better understand the Local Governments' concerns;

iii. Discussions with the Commission, Operator, Surface Owner, Surface Owner's tenant, emergency responders, school officials, hospital administrators, or any other potentially Affected Person; and

iv. Review of public comments.

(3) Results of Consultation.

A. As a result of consultation called for in this subsection, the CDPHE may make written recommendations to the Director about conditions of approval necessary and reasonable to protect public health, safety, welfare or the environment. Such recommendations may include, but are not limited to, monitoring requirements or Best Management Practices. The CDPHE may also recommend that the Commission deny an Oil and Gas Development Plan or Comprehensive Area Plan if necessary and reasonable to protect public health, safety, welfare, or the environment. Where applicable, the CDPHE may also make written recommendations about whether a variance request should be granted or denied, and the reasons for any such recommendations.

B. Standards for Consultation and Director Decision. If the Director agrees that the conditions of approval recommended by the CDPHE are necessary and reasonable to protect public health, safety, welfare, or the environment, the Director will incorporate the CDPHE's recommended conditions into approvals of an Oil and Gas Development Plan or Comprehensive Area Plan. If the Director determines that any conditions of approval recommended by the CDPHE are not necessary and reasonable to protect public health, safety, welfare, or the environment, the Director will explain the grounds for the disagreement in the Director's Recommendation. The Commission will determine whether to follow the CDPHE's recommendation when making a final decision to approve or deny an Oil and Gas Development Plan or Comprehensive Area Plan.

C. Notification of decision to consulting agency. Where consultation occurs, the Director will provide the Director's Recommendation to the CDPHE on the same day that it announces the decision. The CDPHE may petition the Commission to review the Director's Recommendation.

310. SUSPENDING APPROVED OIL AND GAS DEVELOPMENT PLANS. The Director may suspend an approved Oil and Gas Development Plan or any associated drilling and spacing units, Form 2As, or Form 2s if the Director has reasonable cause to believe that information submitted on an application was materially incorrect. An Operator may petition the Commission to review the Director's decision. The Commission will hear the petition at its next regularly scheduled hearing.

311. EXPIRATION. Except as otherwise specified by Rule 314.b.(2), Oil and Gas Development Plans, associated Form 2As, associated Form 2s, and drilling and spacing units will become null and void if drilling operations at every permitted Well have not commenced within 2 years after the date of approval. The Director will not approve extensions to Form 2As or Form 2s. Refiles of Form 2As or Form 2s are not permitted. If a Form 2A or Form 2 expires, the Operator must submit a new Oil and Gas Development Plan or Form 2.

312. COGCC NON-PRODUCED WATER INJECTION. Prior approval of a Form 14A, Authorization of Source of Class II Waste for Disposal, is required for the injection of Class II waste (other than the fluids specifically described in Rules 432 into any formation in a dedicated Class II Underground Injection Control well. Examples include, but are not limited to, ground water recovered during a remediation project or chemical treatments. The Form 14A will include a description of the nature and source of the injected fluids, the types of chemicals used to treat the injected fluids, and the date of initial fluid injection for new injection wells. The Form 14A must be submitted and approved for a new disposal facility and for any changes in the source of Class II waste for an existing facility.

313. Seismic Operations.

a. Operators, or, if applicable, seismic survey contractors, will submit and obtain approval of a Form 20, Permit to Conduct Seismic Operations prior to commencement of seismic operations, including shothole drilling and recording operations.

b. The Form 20 will include the following:

(1) A map at a scale of at least 1:48,000 showing the project boundary, sections, townships and ranges and providing the location of the proposed seismic lines, including source and receiver line locations. The map will also provide county and municipal boundaries and High Priority Habitat.

(2) Any municipal permits, as required by in Rule 313.c.

(3) Any traffic control plan required in Rule 313.d.

(4) Any plan or measures to protect and minimize impacts to wildlife resources developed in coordination with CPW.

(5) Reclamation plan.

c. **Local Government Permits.** Operators will obtain all required Local Government permits prior to commencing seismic operations. Operators will submit copies of the Local Government permits with their Form 20 applications.

d. **Traffic Control and Load Limits.** If the Local Government approval fails to address traffic control and load limits then the Operators will include the following information in traffic control plans submitted with their Form 20 applications:

(1) Confirmation that the Relevant Local Government allows vibroseis units to travel on the public roadways identified in the survey area;

(2) The load limits of all public roads within the survey area; and

(3) A detailed traffic control plan for any activity in a public right-of-way.

e. **Director's Decision.**

(1) The Director may approve the Form 20 if it complies with the Commission's Rules and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director may deny the Form 20 if it does not comply with the Commission's Rules or if it does not adequately protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

f. **Form 20 Expiration.**

(1) An approved Form 20 will expire 6 months from the date of approval.

(2) The Director may grant an extension of time upon written request submitted via a Form 4, Sundry Notice prior to the expiration date of the Form 20.

g. Operators will provide a copy of the approved Form 20 to the Relevant Local Government.

314. COMPREHENSIVE AREA PLANS.

a. **Purpose of Comprehensive Area Plans.**

(1) The Commission intends for Comprehensive Area Plans (CAPs) to facilitate evaluating and addressing cumulative impacts from oil and gas development in a broad geographic area by identifying plans for one or more Operators to develop Oil and Gas Locations within a region while avoiding, minimizing, and mitigating impacts to public health, safety, welfare, the environment, and wildlife in the region through systematic planning of infrastructure location, Best Management Practices, and centralizing facilities.

(2) The Commission intends to create incentives for Operators to develop CAPs by conveying an exclusive right to operate in the area covered by the CAP for an appropriate duration of time, and providing that approved Oil and Gas Development Plans, drilling and spacing units, Form 2As and Form 2s in the CAP expire at the same time that the CAP expires.

b. **Rights Conveyed.**

(1) If the Commission approves a CAP, the approved CAP will convey the exclusive right to develop the oil and gas formation or formations that are the subject of the CAP within the CAP's geographic boundaries for the duration of the CAP as specified by Rule 314.c.

(2) Approved Oil and Gas Development Plans, drilling and spacing units, Form 2As, and Form 2s within an approved CAP will not expire until the CAP expires pursuant to Rule 314.c.

(3) If the Commission approves a CAP, the Operator need not separately evaluate cumulative impacts for each individual Oil and Gas Development Plan proposed within the CAP, as would otherwise be required by Rule 303.a.(5).

(4) Approval of a CAP does not constitute approval of an Oil and Gas Development Plan, drilling and spacing unit, Form 2A, or Form 2. Operators will submit all Oil and Gas Development Plans, drilling and spacing unit applications, Form 2As, and Form 2s as ordinarily required by the Commission's Rules for all locations and Wells within an approved CAP.

c. Duration. Approved CAPs will expire 5 years after the date the Commission approves the CAP, unless:

(1) The Operator requests that the Commission extend the duration of the CAP by submitting an application pursuant to Rule 503.g.(9).

(2) The Operator demonstrates that:

A. It has diligently pursued development of the mineral resources within the CAP; and

B. No significant surface land use changes have occurred within the CAP that would substantially alter the cumulative impacts of the CAP on relevant resources.

(3) The Commission approves the extension of the CAP following a hearing pursuant to Rule 510. The Commission may extend the CAP by any duration it determines is necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources.

(4) If the Commission approves an extension of the CAP, the Operator may re-apply for another extension, subject to the procedures of this Rule 314.c.

d. Submission Procedure.

(1) One or more Operators (collectively, the "Operator") may apply for a CAP at any time by submitting the application materials specified in Rule 314.d. electronically pursuant to Rule 503.g.(9).

(2) The Operator will coordinate with the Director to ensure that the Operator submits all information necessary for the Director and Commission to fully evaluate the CAP's cumulative impacts on public health, safety, welfare, the environment, and wildlife.

(3) At any time after a CAP application is submitted, the Director may request any information necessary to review the CAP application. The Operator will provide all requested information before the Director issues the Director's Recommendation.

(4) When the Director has obtained all information necessary to fully review the CAP's cumulative impacts on public health, safety, welfare, the environment, and wildlife resources, the Director will make a completeness determination.

e. **Informational Requirements for Comprehensive Area Plan.** At a minimum, the Operator will submit the following materials as components of its CAP application.

(1) **Contact Information.**

A. The name, telephone number, and e-mail address for the primary contact person about the CAP for each Operator.

B. The name, telephone number, and e-mail address for the Local Governmental Designee, if applicable, of every Local Government within the CAP's boundaries.

C. The name, telephone number, and e-mail address for all Proximate Local Governments adjacent to the CAP's boundaries.

D. Contact information for all persons who must receive notice pursuant to Rule 314.f.(1)C.

(2) **Fees.** Payment of the full filing and service fee required by Rule 301.e.

(3) Information Requirements.

A. A topographic map at a scale of 1:24,000 showing the area proposed for the CAP showing proposed Oil and Gas Locations.

B. Maps or descriptions of proposed access road locations.

C. Maps or descriptions of proposed gathering line and Flowline infrastructure. ,

D. Maps or descriptions of proposed utility lines.

E. A description of plans for electrification of proposed Oil and Gas Operations.

F. One or more detailed maps showing all High Priority Habitats and federally designated critical habitats for threatened and endangered species within the CAP's boundaries. Operators will rely upon best available information when assessing wildlife habitat within the CAP's boundaries and may provide supplemental site-specific published reports or wildlife surveys.

G. One or more detailed maps generally delineating existing Building Units within the proposed CAP's boundaries and specifically delineating all High-Occupancy Building Units and Designated Outdoor Activity Areas.

(4) **GIS Data.** Geographic Information System (GIS) polygon data to describe the CAP's external boundaries and all relevant features within the CAP.

(5) **Density of Wells.** A proposed density of Wells within the boundaries of the CAP.

(6) **Consolidation of Oil and Gas Locations.** A proposed density of Oil and Gas Locations within the boundaries of the CAP (reported in Oil and Gas Locations per section). This should include a narrative proposal, with maps and appropriate supporting documentation, demonstrating the Operator's plan to consolidate Oil and Gas Locations to the maximum extent possible within the boundaries of the CAP.

(7) **Timing of Operations**. A narrative proposal, explaining the anticipated timing for building infrastructure and developing proposed Oil and Gas Locations.

(8) Infrastructure Planning. A narrative proposal, with appropriate supporting documentation, demonstrating the Operator's plan to consolidate infrastructure within the CAP, the timeline for installing any new infrastructure relative to the planned construction dates for the proposed Wells, and a discussion of any approvals necessary for the infrastructure to be built.

(9) Mineral Rights. A narrative description or map demonstrating the Operator's ownership of mineral rights within the CAP.

(10) Evaluating and Addressing Cumulative Impacts. The Operator will provide a narrative, and, if applicable, quantitative description of cumulative impacts to the following resources, and, if applicable, any Best Management Practices it intends to employ to reduce cumulative impacts on the following resources:

A. Air quality;

B. Water quality;

C. Wildlife;

D. Traffic;

E. Noise;

F. Light;

G. Dust;

H. Odor;

I. Ecosystems, including surface disturbance and soil; and

J. E&P Waste disposal.

(11) Completeness Certification. A certification that the Operator has submitted all materials required by this Rule 314.e.

f. Public Review Process.

(1) Notice.

A. When the Director issues a completeness determination pursuant to Rule 314.d.(4), the Director will post the CAP Application and all supporting materials to the Commission's website. The website posting will provide:

i. The date by which public comments must be received to be considered; and

ii. The mechanism for the public to provide comments.

B. Confidentiality. If the Operator designates any portion of its CAP application as "confidential" pursuant to Rule 222., and the Director agrees with this designation, then such confidential material will be redacted when the CAP is posted to the Commission's website.

C. Within 5 days of the Director issuing the completeness determination, the Operator will provide notice to the following:

i. All owners of minerals that would be developed under the CAP;

ii. All Surface Owners of the Operator's proposed Oil and Gas Locations;

iii. All Local Governments within the CAP's boundaries;

iv. All Proximate Local Governments;

v. The CDPHE;

vi. CPW;

vii. The Colorado State Land Board (if it owns any minerals within the CAP);

viii. The U.S. Bureau of Land Management (if any federal entity owns minerals or surface estate within the CAP);

ix. The Southern Ute Indian Tribe (if the CAP involves any minerals within the exterior boundary of the Tribe's reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Tribe); and

x. All High Occupancy Building Units, Child Care Centers, and the School Governing Body of the School located within the CAP's boundaries.

D. **Procedure for Providing Notice.** The Operator will provide notice required by Rule 314.f.(1).C by one of the following mechanisms:

i. Hand delivery, with confirmation of receipt;

ii. Certified mail, return-receipt requested;

iii. Electronic mail, with electronic receipt confirmation; or

iv. By other delivery service with receipt confirmation.

(2) **Comments.**

A. Comments must be received within 60 days from the date the CAP was posted on the Commission's website to be considered.

B. The Director will post on the Commission's website all comments received unless they contain confidential information.

C. Upon request or by the Director's own initiative, the Director may extend the comment period by any duration determined to be reasonable in order to obtain relevant public input.

(3) **Public Meeting.** An Operator will hold at least 1 informational meeting with all persons or entities entitled to notice 314.f.(1)C.

A. **Timing of Meeting**. The informational meeting will be held during the open public comment period, with sufficient time for the attendees to make comment on the CAP application based on information received. The meeting will be held at a date and time reasonable for most invitees to attend.

B. Content of Meeting. The Operator will provide at a minimum the following information:

i. The schedule of operations;

ii. Maps and figures of the CAP area boundary and all Oil and Gas Locations subject to the CAP; and

iii. Anticipated Best Management Practices to be employed during the term of the CAP to minimize adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

C. The Operator will provide to the Director a summary of the meeting, attendees, questions and concerns expressed, and responses and Best Management Practices designed to minimize and mitigate impacts.

(4) Consultation. Consultation about a CAP will allow the consulting entities to provide input about the cumulative impacts associated with the CAP, timing of operations, consolidation of infrastructure, and conveying the right of Operatorship in the area of the CAP. Consultation about a CAP is intended to be limited to these topics, and is not a replacement for consultation otherwise required for individual Oil and Gas Development Plans.

A. Local Governments.

i. During the public comment period, the Director will engaged in a Formal Consultation Process with all Local Governments and Proximate Local Governments, unless any Local Government waives its right to consultation.

ii. The Local Government Formal Consultation Process will include any relevant topics identified by the Local Government, but will address:

aa. At least the current land use of all areas within the CAP's boundaries, and all future planned land uses of areas within the CAP's boundaries over the anticipated 10-year duration of the CAP; and

bb. Cumulative traffic impacts.

B. CPW.

i. During the public comment period, the Director will engage in a Formal Consultation Process with CPW, unless CPW waives its right to consultation.

ii. The Formal Consultation Process with CPW may address any relevant topic, but will address the proposed CAP's cumulative impacts on wildlife resources and measures to avoid, minimize, and mitigate those impacts.

C. CDPHE.

i. During the public comment period, the Director will engage in a Formal Consultation Process with the CDPHE, unless the CDPHE waives its right to consultation.

ii. The Formal Consultation Process with the CDPHE may address any relevant topic, but will address the proposed CAP's cumulative impacts on public health and the environment, including air quality, water quality, and E&P waste disposal.

g. Director's Recommendation on the Comprehensive Area Plan.

(1) **When the Director May Issue a Recommendation**. The Director will not make a recommendation to the Commission about whether to approve or deny any CAP until after:

A. The Director has fully reviewed the CAP and all supporting application materials and has obtained all information necessary to evaluate the proposed operations and their potential cumulative impacts on public health, safety, welfare, the environment and wildlife resources.

B. The public comment period has ended and the Director has considered all substantive public comments received.

C. The Director has completed the Formal Consultation Process with all Local Governments identified in Rule 314.f.(4).A, CPW, and the CDPHE, unless any such entity waives its right to consultation.

(2) **Director's Recommendation.**

A. **Approval.** The Director may recommend that the Commission approve a CAP that:

i. Complies with all requirements of the Commission's Rules; and

ii. Protects and minimizes adverse cumulative impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

B. **Denial.** If the Director determines that a CAP does not provide necessary and reasonable protections for public health, safety, welfare, the environment, and wildlife resources or fails to protect against cumulative adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations, or fails to meet the requirements of the Commission's Rules, the Director may recommend that the Commission deny the CAP.

(3) **Notice of Director's Recommendation.** Upon issuing the Director's Recommendation, the Director will post the written basis for the Director's Recommendation on the Commission's website, and notify the following persons electronically in a manner determined by the Director:

A. The Operator;

B. All Local Governments within the CAP;

C. All Proximate Local Governments;

D. The CDPHE; and

E. CPW.

(4) **Petition for Review of the Director's Recommendation.** CPW, the CDPHE, any Relevant Local Government or Proximate Local Government, and any owners of minerals within the boundaries of the CAP may petition the Commission to review the Director's Recommendation. Petitions of the Director's Recommendation must comply with Rule 507.

h. Commission's Consideration of a Comprehensive Area Plan.

(1) If the Director recommends approval of a CAP, the CAP will be heard by the Commission in accordance with Rule 509 and Rule 510.

(2) If the Director recommends the denial of the CAP, it will not be considered by the Commission. If the Operator disagrees with the Director's Recommendation, the Operator may petition the Director's Recommendation to the Commission. The petition will be filed and heard in accordance with Rule 507.

(3) **Approval.** The Commission may approve a CAP that complies with all requirements of the Commission's Rules, and protects and minimizes adverse cumulative impacts to public health, safety, welfare, the environment and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

(4) **Denial.** If the Commission determines that a CAP does not provide necessary and reasonable protections for public health, safety, welfare, the environment, and wildlife resources, or that fails to protect against cumulative adverse environmental impacts on any air, water, soil, or biological resource or fails to meet the requirements of the Commission's Rules, the Commission may deny the CAP. The Commission will identify in the record the basis for the denial.

(5) **Stay.** If the Commission determines that additional information or analysis is necessary for it to make a decision to approve or deny a CAP, it may stay consideration of the CAP for further consideration until the Director or Operator can provide the Commission with the additional information or analysis necessary to consider the CAP.

(6) **Final Agency Action.** The Commission's decision to approve or deny a CAP will constitute final agency action. The Commission's decision to stay a CAP for further consideration will not constitute final agency action.

(7) **Changes to an Approved CAP.** Changes to an approved CAP will be approved or denied by the Commission, after appropriate notice, consultation and Director review. The Director will have discretion to determine appropriate notice and consultation requirements based on the scale of the changes.

100 SERIES
DEFINITIONS

PUBLIC WATER SYSTEM (PWS) means a system to provide to the public water for human consumption through pipes or other constructed conveyances, if such systems have at least 15 service connections or regularly serve an average of at least 25 individuals daily at least 60 days out of the year. The definition of PWS includes:

a. Any collection, treatment, storage, and distribution facilities under control of the PWS operator of such system and used primarily in connection with such system.

b. Any collection or pretreatment storage facilities not under such control, which are used primarily in connection with such system.

The definition of PWS does not include any "special irrigation district," as defined in Colorado Primary Drinking Water Regulations (5 C.C.R. 1003.1).

SURFACE WATER SUPPLY AREA means the classified water supply segments and buffers described in Table 411-1 that are within 5 stream miles upstream of a public water system surface water intake on a classified water supply segment or within one-half mile of a Groundwater Under Direct Influence of Surface Water Public Water System supply well.

OPERATIONS AND REPORTING
(400 Series)

401. LOCATION OF WELL COMPLETIONS. All Wells drilled for oil or gas to a common source of supply 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. Operators may request 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 Director will not approve an exception request unless the Operator:

(1) Demonstrates that correlative rights are protected; and

(2) Submits one of the following waivers authorizing the encroachment:

A. If the proposed Well completion encroaches upon an unspaced lease, a waiver will be signed by the lease owner unless Rule 401.c.(2)C. applies.

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

C. 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 all 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 natural fracture or crevice production found in shale, except from fields previously exempted from this Rule.

(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 August 15, 2020, 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 August 15, 2020, remain in effect unless the Form 2 permit 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, Application for Permit-to-Drill 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:

Township 1 North 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

Township 2 North Range 46 West: All Range 47 West: All Range 48 West: All

Township 3 North Range 45 West: Sections 1 through 18 Range 46 West: All Range 47 West: All Range 48 West: All

Township 4 North Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

Township 5 North Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

Township 6 North Range 45 West: All Range 46 West: All Range 47 West: All Range 48 West: All

Township 7 North 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.

(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 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 WLR will be subject to the provisions of Rule 401.c.

g. This 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 WLR Area. This 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 in accordance with the applicable lease, contract terms or established drilling and spacing units recognizing the Owner's right to apply to the COGCC to resolve any outstanding correlative rights issues.

404. Form 4. SUNDRY NOTICES

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 as required by the Commission's Rules or when no other specific form exists.

405. Form 42. FIELD OPERATIONS NOTICE

Operators will submit a Form 42, Field Operations Notice, as designated below and in accordance with a condition of approval on any Form 2, Application for Permit to Drill; Form 2A, Oil and Gas Location Assessment; Form 4, Sundry Notice; 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.

a. **Notice of Intent to Conduct Seismic Operations**. Operators will provide the Commission written notice 72 hours 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 LGD.

b. **Notice of Construction or Major Change.** Operators will provide the Commission written notice 72 hours 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 Local Governmental Designee (LGD), if applicable.

c. Notice of Pit Liner Installation. Operators will provide the Commission written notice 48 hours 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.

e. Notice of Move-In, Rig-Up. Operators will provide the Commission written notice 48 hours in advance of moving-in and rigging-up a drilling or work-over rig on an Oil and Gas Location. Such notice will be provided on a Form 42, Field Operations Notice - Notice of Move-In and Rig-Up. The Commission will provide prompt electronic notice of such intention to the relevant LGD, if applicable

f. Notice of Spud. Operator will provide the Commission written notice 48 hours 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 LGD, if applicable.

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 LGD, if applicable.

l. Notice of Start of Plugging Operations. [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.] 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 Field Operations Notice, Form 42 - Start of Plugging Operations.

m. Notice of High Bradenhead Pressure During Stimulation. [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore

Integrity rulemaking Docket No. 191200754.] 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 Field Operations Notice, Form 42 - 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 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 the Rule 1104.A.(2).b. and Rule 417. Such notice will be provided on a Field Operations Notice, Form 42 - 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.

r. **Abandonment of Flowline**. Operators will provide written notice to the Commission before undertaking and after completing abandonment of on-location Flowlines in accordance with Rule 1105. Such notice will be provided on a Form 42, Field Operations Notice - Abandonment of Flowlines.

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 4, Sundry Notices.

b. **Requirement to Provide Construction Notice.** An advance notice will be provided to the Director on a Form 42, Field Operations Notice, no less than 72 hours prior to commencement of operations with heavy equipment for the construction of an Oil and Gas Location.

c. **Requirement to Post Location Assessment at the Location**. A copy of the approved Form 2A, Oil and Gas Location Assessment, and any Form 4, Sundry Notice, 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 Location, the legal location thereof, and the estimated date of commencement of construction. Such sign will be maintained until Well completion operations and facility operations at the 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 10 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 and mouse holes with materials sufficient to prevent accidental access by people, livestock or wildlife;

C. Fence all cellars; and

D. Maintain all fencing and covers.

(4) If the Operator has not drilled the Well within 3 months of setting the conductor on cropland locations and 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 Rule 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:

(1) Within 45 days of completion of interim reclamation for a new or modified Oil and Gas Location.

(2) Within 45 days of the completion of site construction if interim reclamation does not require the reduction of the Working Pad Surface or will be delayed beyond 45 days after completion of construction.

(3) The Form 45 will include the following information:

A. 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.

B. A surveyed as-built layout drawing of the Oil and Gas Facilities and Production Facilities and other temporary and permanent equipment on the location.

C. A proposed anticipated schedule, by month and year, of the operation phases planned for 1 year following the date the Form 45 is submitted.

D. A description of all conductors that have been set, including:

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

ii. Latitude and longitude of the conductor. If GPS technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 217.

iii. 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.

[The following sections include rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

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 Application for Permit-to-Drill, 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 Field Operations Notice, Form 42, no less than 48 hours 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. 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. The Director will implement these requirements pursuant to the following:

A. 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 in accordance with reasonable requirements of the Director.

B. Surface casing where subsurface conditions are known. For wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing, size 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 true vertical depth (TVD) of the deepest point of the planned well (or as required by Commission order).

C. Alternate isolation by stage cementing.

i. 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.

ii. If unanticipated groundwater is encountered after setting the surface pipe the operator will isolate it by stage cementing the intermediate and/or production string with a solid cement plug extending from 50 feet below the groundwater to 50 feet above it or by other methods approved by the Director in each case.

(2) 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.

(3) All casing cemented in a well will be steel casing.

(4) 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.

(5) Prior written approval from the Director on a Form 4, Sundry Notice, 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.

(6) 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, Sundry Notice, confirming the repairs and approval.

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

(8) Prior written approval from the Director on a Form 4, Sundry Notice, 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 Completed Interval Report, Form 5A 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.

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 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 Sundry Notice, 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 true vertical depth (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 or the reason for the loss of 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 disposal 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 Drilling Completion Report, 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 Application for Permit-to-Drill, 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 Application for Permit-to-Drill, 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.(5).G.i.

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 public health, safety, welfare, the environment, and wildlife resources.

y. Communication Prevention. An Operator will take all prudent 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 treating 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, and 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 [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

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 Application for Permit-to-Drill, 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 Drilling Completion Report, 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 Drilling and Completion Report, 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 Sundry Notice, 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. Definitions. For purposes of this Rule 411:

(1) **Drilling, Completion, Production and Storage ("DCPS") Operations.** DCPS means Oil and Gas Operations at:

A. Oil and Gas Locations for the drilling, completion, recompletion, workover, or stimulation of Wells; or

B. Any other Oil and Gas Location at which Production Facilities are operated.

(2) **Existing Oil and Gas Location** means an Oil and Gas Location, excluding roads, and gathering lines:

A. Permitted or constructed prior to the later of May 1, 2009 for federal land or April 1, 2009 for all other land, or

B. The date that the Oil and Gas Location becomes subject to this Rule 411 by virtue of its proximity to a Classified Water Supply Segment.

(3) **New Oil and Gas Location** means an Oil and Gas Location, excluding roads and gathering lines, that is not an existing Oil and Gas Location.

(4) **New Surface Disturbance** means a surface disturbance that expands the area of surface covered by an Oil and Gas Location beyond that initially disturbed in the construction of the Oil and Gas Location and any disturbance or modification to an existing Oil and Gas Location that requires the approval of a Form 2A, Oil and Gas Location Assessment.

(5) **Non-Exempt Linear Feature** means a road or a pipeline regulated by the Commission that is not necessary to cross a stream or connect or access a well or a pipeline.

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

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

B. 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. Statewide Spill Emergency Notification Procedures. All Operators will evaluate their DCPS operations at Existing Oil and Gas Locations and New Oil and Gas Locations with respect to the downstream surface water hydrology for waterways that may be impacted from spills or releases from their operations, regardless of whether the DCPS operation is within a Surface Water Supply Area.

(1) For all DCPS operations within 2,640 feet of surface water that is 15 stream miles or less upstream from a Public Water System(s) intake(s) or a Groundwater Under Direct Influence (GUDI) Public Water System supply well:

A. The Operator will maintain an emergency response program that includes current contact information for downstream Public Water System(s) and provisions to immediately notify downstream Public Water System(s) within 15 stream miles of the DCPS operations;

B. The Operator will maintain an emergency spill response program that includes employee training, safety, and maintenance and response provisions; and

C. The Operator will maintain the ability to immediately notify any downstream Public Water System(s) with intake(s) within 15 stream miles of the DCPS operations in the event of a Spill or Release.

(2) In the event of a Spill or Release that is reportable under Rule 912, the Operator will immediately implement the emergency response procedures in the above-described emergency spill response program.

(3) In the event of a Spill or Release that is reportable under Rule 912 or has the potential to impact a Public Water System(s), the Operator will notify the affected or potentially affected Public Water System(s) immediately following discovery of the Spill or Release.

c. Applicability Determination.

(1) Rule 411 is applicable to DCPS Operations within and upstream from Surface Water Supply Areas. The applicability of Rule 411 will be determined by field survey verification of proposed DCPS operation locations, the PWS intake or GUDI well, the ordinary-high water mark of the Classified Water Supply Segment, the buffer zones defined in Table 411-1, and the hydrology map submitted with the Form 2A, Oil and Gas Location Assessment. Final applicability of this Rule 411 will be determined by the Director.

(2) With a Form 2A, Oil and Gas Location Assessment, Operators will submit a copy of the Colorado Department of Public Health and Environment's Public Water System Surface Water Supply Area Map for the proposed location as described in Rule 304.b.(14).

(3) DCPS Operations at New Oil and Gas Locations within a Surface Water Supply Area will be subject to the requirements in Rules 411.d, 411.e, or 411.f based on the buffer zones defined in Table 411-1, below. DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area at which no new surface disturbance has occurred after the date Rule 411 became applicable to that Oil and Gas Location will be subject to the requirements in Rule 411.g based on the buffer zones defined in Table 411-1. DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area at which new surface disturbance has occurred after the date Rule 411 became applicable to that Oil and Gas Location will be subject to the requirements in Rule 411.f.(2) based on the buffer zones defined in Table 411-1.

(4) For Classified Water Supply Segments that are perennial and intermittent streams, buffer zones will be determined by measuring from the ordinary high-water mark of each bank to the near edge of the disturbed area at the Oil and Gas Location at which the DCPS Operations will occur. For GUDI wells, measurements will be coordinated with Public Water System(s) so they may identify accurate locations of their water sources.

(5) The buffer zones will apply only to DCPS Operations located on the surface of the Oil and Gas Location. The buffer zones will not apply to subsurface boreholes and equipment or materials contained therein.

TABLE 411-1. Buffer Zones Associated with DCPS Operations.

Zone	Classified Water Supply Segments (ft)	Groundwater wells under the direct influence (GUDI) of surface water (ft)
Internal Buffer	0 - 1,000	0 - 1,000
Intermediate Buffer	1,001 - 1,500	1,001 - 1,500
External Buffer	1,501 - 2,640	1,501 - 2,640

d. Requirements for DCPS Operations Conducted at New Oil and Gas Locations in the Internal Buffer Zone.

DCPS Operations conducted and Non-Exempt Linear Features located at New Oil and Gas Locations and New Surface Disturbance may not occur in whole or in part within the Internal Buffer Zone of a Surface Water Supply Area identified in Table 411-1 unless a variance is granted by the Commission pursuant to Rule 502.b and consultation with the Colorado Department of Public Health and Environment occurs pursuant to Rule 309.f and a Form 2A, Oil and Gas Location Assessment, or Comprehensive Area Plan has been approved with appropriate conditions of approval. In determining appropriate conditions of approval for such operations, the Director will consider the extent to which the conditions of approval are required to prevent impacts to the Public Water System.

(1) The Commission will not grant a variance unless the Operator demonstrates that:

A. The proposed DCPS Operations and applicable Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality in the Surface Water Supply area; and

B. Conducting the DCPS Operation outside the Internal Buffer Zone would pose a greater risk to public health, safety, welfare, the environment or wildlife resources, such as may be the case where conducting the DCPS Operations outside the Internal Buffer Zone would require construction in steep or erosion-prone terrain or result in greater surface disturbance due to an inability to use infrastructure already constructed such as roads, well sites, or pipelines.

(2) At a minimum, for any DCPS Operation or New Surface Disturbance at a New Oil and Gas Location within the Internal Buffer Zone, the Director will include as conditions of approval in the Form 2A, Oil and Gas Location Assessment, or Comprehensive Area Plan, the requirements of Rule 411.d and e.

e. Requirements for DCPS Operations at New Oil and Gas Locations in the Intermediate Buffer Zone.

(1) The following will be required for all DCPS Operations at New Oil and Gas Locations within a Surface Water Supply Area and in the Intermediate Buffer Zone as defined in Table 411-1.

A. Flowback and stimulation fluids contained within tanks that are placed on a working pad surface in an area with downgradient perimeter berming;

B. Lined berms or other lined containment devices will be constructed in compliance with Rule 603.s. around crude oil, condensate, and produced water storage tanks;

C. Daily inspection of the Oil and Gas Location for compliance with Rule 411; and

D. During drilling and completion operations, the Operator will maintain spill response equipment at the Oil and Gas Location.

(2) Pits are prohibited within the Intermediate Buffer Zone.

(3) The following chemicals listed in Table 411-2 are prohibited as additives in Hydraulic Fracturing Fluid within the intermediate buffer zone. This prohibition does not prevent Operators from recycling or reusing produced water that may have trace amounts of chemicals listed in Table 411-2 as Hydraulic Fracturing Fluid. For any chemical constituent for which Table 915 provides a standard, the concentration will be below the Table 915 standard.

TABLE 411-2. 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	744043- 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
polysorbate 80	9005- 65- 6
Quatemary 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

(4) DCPS Operations at New Oil and Gas Locations and New Surface Disturbances within the Intermediate Buffer Zone will comply with the requirements of Rule 411.f.

f. Requirements for DCPS Operations at New Oil and Gas Locations within the External Buffer Zone.

The following will be required when DCPS Operations are conducted at New Oil and Gas Locations within a Surface Water Supply Area and in the External Buffer Zone as defined in Table 411-1.

(1) Pitless drilling systems; and

(2) When sufficient water exists in the Classified Water Supply Segment, collection of baseline surface water data consisting of a pre-drilling surface water sample collected immediately downgradient of the Oil and Gas Location and follow-up surface water data consisting of a sample collected at the same location 3 months after the conclusion of any drilling activities and operations or completion. In addition to the requirements of Rule 615, the Director may require the Operator to install and sample site-specific Groundwater monitoring wells. The Operator will sample the GUDI well(s) within 2,640 feet of the Oil and Gas Location unless the PWS Well Operator does not consent to the sampling. The sample parameters for both Groundwater and surface water samples will include:

A. pH;

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

C. Specific conductance;

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

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

F. Total dissolved solids;

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

H. Diesel Range Organics (DRO – C10 to C28) and Gasoline Range Organics (GRO – C6 to C10);

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

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

(3) Current applicable EPA-approved analytical methods for drinking water will be used and analyses will be performed by laboratories that maintain state or nationally accredited programs.

(4) Copies of all test results described above will be provided to the Director and the potentially impacted Public Water System(s) within 60 days of collecting the samples. In addition, the analytical results and surveyed sample locations will be submitted to the Director in an electronic data deliverable format via Form 43.

g. Requirements for Ongoing DCPS Operations at Existing Oil and Gas Locations.

(1) Except for New Surface Disturbance, existing Oil and Gas Locations and ongoing DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area and within zones specified in Table 411-1 will be subject to the following requirements instead of the requirements of Rules 411.d, 411.e, or 411.f provided that no new surface disturbance at the Existing Oil and Gas Location occurs after the date Rule 411. became applicable to the Oil and Gas Location:

A. Collection of surface water data from a Classified Water Supply Segment consisting of a sample collected immediately downgradient of the oil and gas operation will occur by the latest of June 1, 2009, within 6 months after the date Rule 411. became applicable to the Oil and Gas Location, or when sufficient water exists in the stream. In addition, the Operator will sample the GUDI well(s) within 2,640 feet of the Oil and Gas Location. The sample parameters for both groundwater and surface water samples will include:

i. pH;

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

iii. Specific conductance;

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

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

vi. Total dissolved solids;

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

viii. Diesel Range Organics (DRO – C10 to C28) and Gasoline Range Organics (GRO – C6 to C10);

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

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

B. Current applicable EPA-approved analytical methods for drinking water will be used and analyses will be performed by laboratories that maintain state or nationally accredited programs.

C. Copies of all test results described above will be provided to the Director and the potentially impacted Public Water System(s) within 60 days of collecting the samples. In addition, the analytical results and surveyed sample locations will be submitted to the Director in an electronic data deliverable format via Form 43.

D. Operators will employ and maintain Best Management Practices, as necessary, to protect the Surface Water Supply Area.

E. If an existing Well is restimulated within the Intermediate or Internal Buffer Zone, the chemicals listed in Rule 411.e.(4) will be prohibited.

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 Local Governmental Designee in whose jurisdiction the Well is to be drilled. 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 shall 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 Well Operations.** An Operator will provide to the Surface Owner or agent at least 7 days advance notice of subsequent Well operations with heavy equipment that will materially impact surface areas beyond the existing access road or Well Site, such as recompleting or stimulating the Well.

(5) **Notice During Irrigation Season.** If a Well is to be drilled on irrigated crop 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 shall 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 the Move-In, Rig-Up of 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;

and

G. The COGCC's website address and telephone number.

(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 Move-In, Rig-Up of the 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 Underground Injection Control well on a Form 7, Operator's Monthly Report of Operations, 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 Class II fluids not listed in 414.b. injected into a Class II Underground Injection Control well on a Form 14, Monthly Report of Non-Produced Water Injected, as described in Rule 807.b.

414. Form 5. DRILLING COMPLETION REPORT [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

a. Preliminary Drilling Completion Report, Form 5

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

(2) **Information Requirements.** The "Preliminary" Drilling Completion Report, Form 5 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 “Final” Form 5 will be submitted after reaching total depth as required by Rule 414.b.

b. Final Drilling Completion Report, Form 5

(1) A “Final” Drilling Completion Report, Form 5, 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 Final Form 5 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 “Final” Drilling Completion Report, Form 5 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 Sundry Notice, Form 4.

E. Any directional survey will be attached to the form and will meet the requirements set forth in Rule 409.

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 true vertical depth (TVD) in feet of the surface casing shoe expressed in psig.

(3) The Operator will submit a Drilling Completion Report, 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 be limited to, the operations listed in Rule 408.e.(5). The Drilling Completion Report, Form 5 will include the information required in 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, unless 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 [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

a. The Operator will submit the Completed Interval Report, Form 5A, within 30 days after a formation is completed (successful or not); after a formation is temporarily abandoned or permanently abandoned; after a formation is recompleted, reperforated, or restimulated; and after a formation is commingled.

b. The Operator will report the details of hydraulic fracturing treatment, acidizing stimulation, or other stimulation, including the fluid volumes and items required on the Form 5A.

c. In order to resolve completed interval information uncertainties, the Director may require an operator to submit further information in an additional Completed Interval Report, 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 well bore:

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 subparagraph (3), additional mechanical integrity tests will be performed on each type of injection well as follows:

A. **Dedicated Injection 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.

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.

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 section.

(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 Completions 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, Field Operations Notice - 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 Rule 417.b.(1) and 417.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 DURING WELL STIMULATION OPERATIONS [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

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 use for annular pressure monitoring will remain exposed and the 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 public health, safety, welfare, the environment, including groundwater, potential flow zones, and formations, and wildlife resources and in accordance with 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 true vertical depth (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 true vertical depth (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, Field Operations Notice, 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.

I. 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.

II. 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 Sundry Notice, 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. An operator will:

A. Report to the Director bradenhead pressure which is greater than 30% of the true vertical depth (TVD) in feet of the surface casing shoe expressed in psig, or a lower threshold set by a Commission Order, or any well that flows liquids or continuous gas from the bradenhead annulus on a Form 17, Bradenhead Test;

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 Sundry Notice, 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 Sundry Notice.

(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 in accordance with Rule 614.c.

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 [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]**

The Operator will submit results of bradenhead tests to the Director within 10 days of completing the test either by filing a Form 17 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:

(1) The following requirements apply to new Oil and Gas Locations and Wells:

A. 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.

B. 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.

C. 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.

(2) The following requirements apply to all Wells, Tanks, separation equipment, containment berms, Production Pits, Special Purpose Pits, and flowback pits:

A. 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.

B. 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.

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

D. 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 Local Government requirements unless the Local Government's requirement is less protective than the Commission's Rules, guidance, conditions of approval, or any other requirement.

423. NOISE

a. Operators will submit a noise mitigation plan that demonstrates their capability 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). 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) The preliminary locations where noise monitoring will be conducted pursuant to Rule 423.c.

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. Where required, the Director will include a Condition of Approval on the Form 2A requiring the Operator to 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. 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. 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:

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	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	70 db(C)	65 db(C)

(2) Drilling or completion operations, including flowback, in Residential/Rural or Commercial/Agricultural, maximum permissible noise levels will be 60 db(A) in the hours between 7:00 pm to 7:00 am and 65 db(A) in the hours between 7:00 a.m. to 7:00 p.m. unless otherwise required by Rule 423.

(3) The Director may consult with a Local Government to identify the type of land use of the 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. The Director may require Operators to comply with a lower maximum permissible noise level in consultation with local governments, the Colorado Department of Public Health and Environment, or Colorado Parks and Wildlife.

C. If a Local Government requests a higher maximum permissible noise level than would otherwise be allowed by Rule 423.b(1), the Director may apply that level as long as the requested level is protective of public health, safety, and welfare and wildlife.

(4) When operating in or within 2,000 feet of High Priority Habitat, Operators will consult CPW and, on federal lands, the Bureau of Land Management (BLM), or United States Fish and Wildlife Services (USFWS) Wildlife, to determine the acceptable noise limits and monitoring protocols.

(5) Operators may exceed the noise levels in Rule 423.b. measured at the property line or occupied structure if all surface owners and tenants within 2,000 feet of the Working Pad Surface agree in writing to the exceedance.

(6) During the hours between 7:00 a.m. and the next 7:00 p.m. the maximum permissible noise levels listed in Rule 423.b.(1) may be increased 10 dB(A) for a period not to exceed 15 minutes in any 1 hour period.

(7) Operators will reduce periodic, impulsive, or shrill noise by 5 dB(A) below the levels in Rule 423.b.(1).

(8) Pursuant to Commission inspection or upon receiving a complaint from a Local Governmental Designee, if applicable, 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 Rule 423.b.(1) and Rule 423.d.(3) 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, 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 the property boundary of at least 5 representative residential Building Units, unless there are less than 5 residential Building Units within 2,000 feet.

(2) If an Operator is unable to obtain access to the surface from the requisite number of Building Unit owners or tenants or Surface Owners, the Operator may seek a variance from the Director pursuant to Rule 502.a.

(3) **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 property line.

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 a different distance and extrapolate it to the compliance point using the following formula:

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

(4) 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.

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

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

(7) 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 calibrated pre-survey and post survey. Continuous surveys will be calibrated pre-survey and post survey and at least every 7 days until monitoring is completed. All survey equipment will be inspected at time of calibration for compliance to these rules.

(8) 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).

(9) If a Building Unit, High Priority Habitat, or Designated Outside Activity Area is built or designated after an Oil and Gas Location is permitted, 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, Sensitive Wildlife Habitat, or Designated Outside Activity Area.

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

(1) Noise measurements will take into account ambient noise, rather than solely the incremental increase of noise from the facility targeted for measurement.

(2) If ambient noise levels already exceed the noise thresholds identified in 423.b.(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 ever increase noise above the maximum cumulative noise thresholds specified in Rule 423.d.(3).

(3) If ambient noise levels already exceed the maximum permissible noise thresholds identified in 423.b.(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:

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)

424. LIGHTING

a. Operators will submit a light mitigation plan as an attachment to their Form 2As, as required by Rule 304.c.(3).

(1) All light mitigation plans will be certified by a qualified professional.

(2) All light mitigation plans will address:

A. A pre-production facility lighting plan demonstrating compliance with Rule 424.c.;

B. A post-production facility lighting plan;

C. The Operator's capability of meeting all requirements of this Rule 424;

D. The location of all outdoor lighting on the site;

E. The location of the nearest building or area listed in Rules 424.c and 424.d; and

F. For any location with a building unit within 2,000 feet, a metric of perimeter light intensity at the property line of any Building Unit within 2,000 feet.

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 intensity, 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 and Maintenance 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 in compliance with 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 in Certain Areas.** At all Oil and Gas Facilities, after the Commencement of Production Operations, Operators will develop site lighting to reduce nighttime light intensity from an Oil and Gas Facility to 1 lumen at any of the following locations within 2,000 feet, measured at 5.5 feet above grade in a direct line of sight to the brightest light fixture onsite:

(1) The outer wall of any residential Building Unit;

(2) The outer wall of any High Occupancy Building Unit;

(3) The outside boundary of any High Priority Habitat or State Wildlife Area; and

(4) The outside boundary of any Wilderness Area, National Park, National Monument, or State Park.

e. **Production Phase Facility Lighting in Other Areas.** At all Oil and Gas Facilities not located in the areas specified by Rule 424.d., after the date of first production, Operators will develop site lighting to reduce nighttime light intensity from an Oil and Gas Facility to 3 lumens at any of the following locations within 2,000 feet, measured at 5.5 feet above grade in a direct line of sight to the brightest light fixture:

(1) Any industrial building;

(2) Any commercial building; and

(3) Any public road or highway.

f. **Cumulative Light Impacts.** Operators will develop site lighting to reduce cumulative nighttime light intensity from all Oil and Gas Facilities to 4 lumens 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. 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.

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

426. ODORS

a. Operators will submit an odor mitigation plan as an attachment to their Form 2As, as required by Rule 304.c.(4). All odor mitigation plan will address:

(1) How the Operator will comply with all requirements of this Rule 426; 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 Outdoor Activity Area, Operators will use Best Management Practices to minimize odors, which may include, but are not limited to:

(1) Adding an odorant which is not a masking agent to drilling mud systems and/or fracturing fluids;

(2) Adding chillers to drilling mud systems;

(3) Using a filtration system to minimize odors from drilling and fracturing fluids;

(4) Wiping down and internally flushing drill pipe during drilling operation trips out of a hole;

(5) Increasing odorant concentration during peak hours, unless the odorant creates a separate odor;

(6) Using a low-odor drilling fluid; and

(7) Including base fluid to use and storage of drill cuttings after leaving the shale shakers.

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 Local Governmental Designee, if applicable, 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 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 Outdoor 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, including access roads, that demonstrates their capability of meeting the requirements of this Rule 427 as an attachment to their Form 2As, as required by Rule 304.c.(5). Such plans will include at least the following information:

(1) Soil type;

(2) Proposed maximum allowable wind speed at which fugitive dust mitigations will no longer be able to control fugitive dust and therefore operations will cease, (including peak, average, and sustained);

(3) Proposed vehicle speed limit to minimize dust;

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

(5) Whether access roads are paved;

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

(7) Silica dust content;

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

(9) 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;

C. Restricting construction activity during high- wind days; and

D. Silica dust controls.

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.

(2) Compliance with a Dust Minimization Plan submitted under 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. Exploration and Production 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 Governmental Designee, if applicable. 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 Director 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 Report, for reportable spills or releases providing all details required on the Form.

429. MEASUREMENT OF OIL

a. 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 Rule 429.b. and c. below. This Rule 429 will be used consistently with standards established by the American Society for Testing and Materials (ASTM), the American Petroleum Institute (API) Manual of Petroleum Measurement Standards, the American Gas Association (AGA), the Gas Processors Association (GPA), or other applicable standards-setting organizations, and pursuant to contractual rights or obligations. Only those editions of standards in effect as of July 1, 2020 apply, later amendments do not apply. The material cited in this Rule 429 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, these materials may be examined at any state publication depository library.

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) in accordance with ASTM D-1250 Table 7, or any close approximation thereof approved by the Director.

d. **Gravity Determination.** The gravity of oil at 60° F will be determined in accordance with ASTM D-1250 Table 5, or any close approximation thereof approved by the Director.

e. **Tank Gauging.** Measurement by tank gauging will be completed in accordance with industry standards as specified in:

(1) The API Manual of Petroleum Measurement Standards, Chapter 3.1A Standard

Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, August 2005) and no later editions;

(2) The API Manual of Petroleum Measurement Standards, Chapter 3.1B Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, June 2001) and no later editions;

(3) The API Manual of Petroleum Measurement Standards, Chapter 3.1A Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, August 2005) and no later editions;

(4) The API Manual of Petroleum Measurement Standards Chapter 18.1 - Custody Transfer - Section 1-Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck (Second Edition, April 1997) and no later editions, or

(5) The 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) and no later editions.

(6) The API Manuals identified in (1) through (6) above 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 API Manuals may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000.

f. **Metering Station.** Measurement will be completed in accordance with industry standards as specified in API CH. 4 Proving Systems (Section 2, Third Edition September 2003 and Section 8, First Edition November 1995), API CH. 5 Metering (CH. 5.1 Fourth Edition October 2005, CH. 5.2 Third Edition October 2005, CH. 5.3 Fifth Edition September 2005, CH. 5.4 Second Edition July 2005, CH. 5.5 Second Edition July 2005, and CH. 5.6 First Edition October 2002), API CH. 7 Temperature Determination (First Edition June 2001), API CH. 8 Sampling (CH. 8.1 Third Edition October 1995 and CH. 8.2 Second Edition October 1995), and the API CH. 12, Calculation of Quantities (CH. 12.1 Part 1 Second Edition November 2001).

g. **LACT Meters.** Measurement utilizing LACT units will be in accordance with industry specifications or standards as specified in API SPEC. 6.1, Lease Automatic Custody Transfer Systems (Second Edition May 1991).

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 or Proceeds – Sale Volume Reconciliation Payor Contact Form to the payor 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 payor will return the completed form to the payee within 60 days of receipt. Submittal of this form to the payor 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 payor 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 may be submitted by the payee at any time. A Form 37 requesting information concerning sales volume reconciliation will be submitted by the payee within one year of receipt of payment or the notification of a revised payment. The Commission may act to prohibit or terminate any abuse of the reconciliation process, such as the submittal by a payee of multiple repeated requests for sales volume reconciliation regarding the same Well. Such action by the Commission may include, but is not limited to, relieving the payor from its obligation to answer the request and limiting or prohibiting the payee's submittal of additional requests.

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 have a legible copy of the last meter calibration report available at all times.

430. MEASUREMENT OF GAS

a. 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. This Rule 430 will be used consistently with standards established by the American Society for Testing and Materials (ASTM), the American Petroleum Institute (API) Manual of Petroleum Measurement Standards, the American Gas Association (AGA), the Gas Processors Association (GPA), or other applicable standards-setting organizations, and pursuant to contractual rights and obligations. Only those editions of standards cited within this Rule 430 will apply to this rule; later amendments do not apply. The material cited in this rule 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, these materials may be examined at any state publication depository library.

b. **Metering Station.** Installation and operation of gas measurement stations will be in accordance with industry standards as specified in API CH. 14.3, Orifice Measurement (Part 2, Fourth Edition April 2000 and Part 3, Third Edition August 1992 and Part 4, Third Edition November 1992); API CH. 21.1, Electronic Measurement (gas) (First Edition September 1993); AGA Report #7, Turbine Measurement (January 2006); AGA Report #9, Ultrasonic Measurement (April 2007); and AGA Report #11, Coriolis Measurement (January 2003).

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 CH. 22, Testing Protocol Standards (CH. 22.1 First Edition November 2006 and CH. 22.2 First Edition August 2005).

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 have a legible copy of the last meter calibration report available 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, Operator's Monthly Report of Operations. 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 in accordance with industry standards as specified in API CH. 14.1, Gas Sampling (Fifth Edition February 2006); GPA 2166, Gas Sampling (Revised 2005); GPA 2261, Gas Analysis (Revised 2000); GPA 2286, Extended Analysis; GPA 2145, Gas Physical Properties (Revised 2003); and GPA 2172, Gas Heating Value (Revised 1996).

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, Payment or Proceeds – Sale Volume Reconciliation Payor Contact Form 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 may be submitted by the payee at any time. A Form 37 requesting information concerning sales volume reconciliation will be submitted by the payee within one year of receipt of payment or the notification of a revised payment. The Commission may act to prohibit or terminate any abuse of the reconciliation process, such as the submittal by a payee of multiple repeated requests for sales volume reconciliation regarding the same Well. Such action by the Commission may include, but is not limited to, relieving the payer from its obligation to answer the request and limiting or prohibiting the payee's submittal of additional requests.

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 in the Form 7, Operator's Monthly Report of Operations.

b. The volume of produced water reused or recycled in drilling and completion operations will be measured in terms of barrels and reported on the Form 5, Drilling and Completion Report, and the Form 5A, Completed Interval Report, respectively.

c. The volume of water injected into a Class II dedicated injection 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. A legible copy of the last meter calibration report will at all times be made available at the meter. The volume of injected water will be reported in the Form 7, Operator's Monthly Report of Operations.

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 in the Form 7, Operator's Monthly Report of Operations.

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 in accordance with 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. [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

The requirements for abandoning a Well are as follows:

a. Plugging

(1) An Operator will plug 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 Notice of Intent to Abandon, Form 6. 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 Well Abandonment Report, Form 6, and include a job log 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 in accordance with 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 shall remain in place. If an Operator requests temporary abandonment status in excess of 6 months the Operator shall state the reason for requesting such extension and state plans for future operation. A Sundry Notice, 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 Rule 306.a.(5), kept in force until such time as the Well is permanently abandoned.

(3) An Operator will abandon any Well which 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 REPORT

a. Notice of Intent to Abandon, Form 6. Prior to the abandonment of a well, a Well Abandonment Report, Form 6 – 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.

b. Subsequent Report of Abandonment, Form, 6.

(1) Within 30 days after abandonment, the Well Abandonment Report, Form 6 - 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 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 Well Abandonment Report, 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 releases occurred or may occur;

B. Re-entering the Well to complete additional remediation 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 Well Abandonment Report, Form 6 – Notice of Intent to Abandon, will be submitted to, and approved by, the Director prior to the re-entry of a plugged and abandoned Well for the purpose of re-plugging the Well. A Well Abandonment Report, 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 72 hours 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.

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 a Relevant Local Government, 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 set back 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 set back 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. and 436.b.

d. Vibration Limits.

(1) Operators will determine in advance safe set back distances from both surface structures and subsurface utilities/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 Operator Investigations 8507 (November 1980) are not exceeded.

(3) Unless a lower limit is required by a utility owner or a 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 in accordance with local, state and federal rules.

(2) **Blasting Safety Setbacks**. Operators will keep blasting a safe distance from a building unit, water well or spring, unless otherwise authorized in writing by the Surface Owner or lessee, 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

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
15	16	864
16	17	901
17	18	936
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 via a Form 4, Sundry Notice, from the Director pursuant to Rule 502.a. 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 notice of intent 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 ground water 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. Map(s) (with a scale not less than 1:48,000) showing the location of all receiver lines and the location of all energy source lines.

B. 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. The shotholes on the map;

B. Any shotholes encountering artesian water on the map;

C. A certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by these rules; and

D. The latitude and longitude of each shothole location. The latitude and longitude coordinates will be referenced 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 N, longitude 104.45632 W) or reported in other form as approved by the Director. If GPS technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 216.

(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.

g. Financial Assurance Requirements. The Operator will file financial assurance in accordance with Rule 705 prior to submitting the Form 20, Permit to Conduct Seismic

Operations. The financial assurance will remain in effect until the following conditions have been met:

(1) The Operator has submitted and the COGCC 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 in accordance with Rule 436.h;

(3) All complaints received from Surface Owners have been investigated, addressed and resolved by the Director as provided for in Rule 522;

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

(5) The reclamation has passed final inspection.

h. Reclamation Requirements. Upon completion of seismic operations, the Operator will restore the surface of the land as nearly as practicable 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.

DEFINITIONS
(100) SERIES

AFFECTED PERSON means any person who satisfies the requirements of Rule 507.a.

GOVERNMENTAL AGENCY means any federal, state, tribal or local governmental entity.

RULES OF PRACTICE AND PROCEDURE

501. APPLICABILITY OF RULES OF PRACTICE AND PROCEDURE

a. General. These rules will be known and designated as "Rules of Practice and Procedure before the Oil and Gas Conservation Commission of the State of Colorado," and will apply to all proceedings before the Commission. These rules will be liberally construed to secure just, speedy, and inexpensive determination of all issues presented to the Commission, Administrative Law Judges, and Hearing Officers.

b. Prohibition of abuse. Notwithstanding any provision of these rules, the Commission, or Administrative Law Judge, or Hearing Officer will, upon its own motion or upon the motion of a party to a proceeding, act to prohibit or terminate any abuse of process by an applicant, petitioner, witness, or party offering a statement pursuant to Rule 512 in a proceeding. Such action may include, but is not limited to; summary dismissal of the application, petition, or other pleading; limitation or prohibition of harassing or abusive testimony; limitation or prohibition of excessive motion filing; restricted discovery; and finding a party in contempt. Grounds for such action may include, but are not limited to, the use of the Commission's procedures for reasons of obstruction and delay; misrepresentation in pleadings or testimony; or, other inappropriate or outrageous conduct that is deemed by the Commission, Administrative Law Judge, or Hearing Officer to be an abuse of process.

c. Before the Commission adopts any rule or regulation, or enters any order, or amendment thereof or grants any variance pursuant to Rule 502.b, the Commission, Administrative Law Judge, or Hearing Officer will hold a public hearing at such time and place as may be prescribed by the Commission, Administrative Law Judge, or Hearing Officer. Any party will be entitled to be heard as provided in these rules and regulations. The foregoing will not apply to recommended orders of uncontested matters, the issuance of an emergency order, Notice of Alleged Violation, or Cease and Desist Order.

d. Judicial review. Any rule, regulation, permit, or final order of the Commission, whether approved by the Director or the Commission, is subject to judicial review in accordance with the provisions of the Administrative Procedure Act, §§ 24-4-101 to -108, C.R.S. The statutory time period for filing a notice of appeal from any Commission decision commences pursuant to § 24-4-106(4), C.R.S.

502. VARIANCES

a. Variances Sought from Director. Variances to any Commission Rule, regulation, or order may be granted in writing by the Director without a hearing upon written request by an Operator to the Director, or by the Commission after hearing upon application. The Operator or the applicant requesting the variance will make a showing that it has made a good faith effort to comply, or is unable to comply with the specific requirements contained in the Commission Rule, regulation, or order, from which it seeks a variance, including, without limitation, securing a waiver or an exception, if any, and that the requested variance will not violate the basic intent of the Act , minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protects against adverse environmental impacts on any air, water, soil, or biological resource.

b. Variances Sought from Commission. For purposes of seeking a variance from the Commission, only the Operator or an applicant authorized by the Commission's Rules, may file an application seeking the Commission's approval of a variance.

c. No variance to the Commission's Rules and regulations applicable to the Underground Injection Control Program will be granted by the Director without consultation with the U.S. Environmental Protection Agency, Region VIII, Waste Water Management Division Director.

d. All Director-granted variances will be reported to the Commission at its next scheduled hearing following the date that the variance was granted.

e. Notice of all granted variances also will be posted on the Commission's website.

503. APPLICATIONS FOR A HEARING BEFORE THE COMMISSION

a. Commission's own motion. The Commission may, on its own motion, initiate proceedings upon any question relating to oil and gas operations in the State of Colorado, or to the administration of the Act, by notice of hearing or by issuance of an emergency order without notice of hearing. Such emergency order will be effective upon issuance and will remain effective for a period not to exceed 14 days. Notice of an emergency order will be given as soon as practicable after issuance.

b. All proceedings that require a Commission decision, other than those initiated by the Commission, must be commenced by filing an application for a hearing before the Commission.

c. All applications will include at a minimum:

(1) the applicant's name and email address;

(2) if the applicant is an Operator registered with the Commission, the Operator's Commission identification number;

(3) Identification of the type of application submitted;

(4) all geologic formations, if necessary for adjudication of the application;

(5) location of applicable lands (including county, field name, Township / Range / Section, and nearby public crossroads) and map of the same;

(6) the name and contact information (including email) for an Operator or applicant representative designated to receive questions, and petitions;

(7) a description of the relief requested, set forth in reasonable detail;

(8) the legal and factual grounds for the requested relief;

(9) a prayer for relief;

(10) if applicable, the name, mailing address, phone number, and email address of the applicant's legal counsel;

(11) the name of each person entitled to receive notice of the application under the Commission's Rules; and

(12) any information required by the Commission's rules that is specific to the application.

d. All applications will be executed by a person with authority to do so on behalf of the applicant, and the contents thereof will be verified by a party with sufficient knowledge to confirm the facts contained therein.

e. The originally signed application will be maintained by the filing party. The electronically submitted application, and all subsequent documents submitted, are Commission public records.

f. Each application, except those filed by a Governmental Agency, or the Commission, will be accompanied by a docket fee established by the Commission (see Appendix III).

g. **Commission Application Types.** The following applications may be filed with the Commission for adjudication:

(1) **Oil and Gas Development Plan.** An Oil and Gas Development Plan application must satisfy the requirements set forth in Rule 303. Only an Owner or Operator may file an Oil and Gas Development Plan.

(2) **Drilling Units.** Pursuant to Rule 304, applications for the creation of drilling units, additional wells within existing drilling units, other applications for modifications to existing drilling unit orders, or applications for exception locations.

(3) **Pooling and Unitization Applications.** A statutory pooling application filed pursuant to § 34-60-116, C.R.S., or a unitization application filed pursuant to § 34-60-118, C.R.S. A statutory pooling application must satisfy the information requirements set forth in Rule 506.

(4) **Order Finding Violation.** An Order Finding Violation (OFV) application must include the Notice of Alleged Violation. Only the Director may be the applicant for an OFV.

(5) **Payment of Proceeds.** A payment of proceeds application must satisfy the information requirements set forth in Rule 429 or Rule 430 and be submitted on a Form 38, Payment of Proceedings Hearing Request.

(6) **School and Child Care Center Setbacks.** A school and child care center setback application must satisfy the information requirements set forth in Rule 604.b.(6).B.

(7) **Petition for Review.** A complainant's Petition for Review must satisfy the requirements of Rule 524.f.

(8) **Comprehensive Area Plan.** A Comprehensive Area Plan must satisfy the requirements of Rule 314. Only an Owner or Operator may file a Comprehensive Area Plan.

(9) **Variances**. An application for a variance must satisfy the requirements of Rule 502.b.

(10) Any person may seek relief or a ruling from the Commission on any other matter not described in (1) through (9) above.

h. Unless provided for in the Commission's Rules, or the Commission otherwise orders, all matters submitted to the Commission for adjudication will automatically be assigned to an Administrative Law Judge, or Hearing Officer. An assignment to an Administrative Law Judge, or Hearing Officer will encompass all issues of fact and law concerning the matter unless the Commission specifies otherwise in a written order. Notwithstanding the foregoing, the following will be considered by the Commission:

(1) Approval of Comprehensive Area Plans filed pursuant to Rule 314;

(2) Applications seeking a hearing pursuant to 604.x.(X);

(3) Variance requests to the Commission filed pursuant to Rule 502.b.; and

(4) Rulemaking proceedings held in accordance with Rule 529.

i. The Commission, Director, Administrative Law Judge, or Hearing Officer may require any additional information necessary to ensure the application is complete. The Commission, Administrative Law Judge, or Hearing Officer may issue an order rejecting an application if the application is found to be without merit or is incomplete. The rejection of an application will be in writing and constitute a final agency order that is subject to judicial review.

j. A party filing an application may amend its application at any time prior to notice being sent consistent with Rule 504. A material amendment is a change that substantially alters the requested relief of the original application, requires notice to additional persons, or as otherwise determined by the Commission, Administrative Law Judge, or Hearing Officer. If the application requires a material amendment, the Commission, Administrative Law Judge, or Hearing Officer may in its discretion dismiss the application.

k. Upon the acceptance of an application:

(1) The Commission will assign the application a docket number.

(2) The matter will be set for hearing and notice of that hearing will be given in accordance with Rule 504.

l. The Commission, Administrative Law Judge, or Hearing Officer will grant the first request by an applicant for a continuance of any uncontested application. The Commission, Administrative Law Judge, or Hearing Officer has discretion to grant or deny subsequent requests for a continuance of an uncontested application.

m. As necessary, or if required by the Commission's Rules, Commission staff will evaluate all applications and prepare an evaluation, which may include a recommendation on the merits of the application. Any such evaluation or recommendation will be part of the administrative record to be considered by the Commission, Administrative Law Judge, or Hearing Officer.

n. Subsequent to the initiation of a proceeding, all pleadings filed by any party will reference the docket number assigned to such proceeding. Each pleading will include a certificate of service identifying the document served and filed with the Commission and that the pleading was served on all parties, by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served in accordance with Rule 522.

504. NOTICE FOR HEARING

a. General notice provisions.

(1) When any proceeding has been initiated, the Commission will require a copy of the application, together with a notice of such proceeding, to be provided to all persons specified in the relevant sections of Rules 504.b., 504.c., and 504.d. at least 60 days in advance of the noticed hearing date. Notice will be provided in accordance with the requirements of § 34-60-108(4), C.R.S., and will be drafted by the Secretary. A signed, electronic copy will be provided to the applicant in sufficient time for delivery to those who require notice. The application and notice will be provided directly by the applicant, using the applicant's return address. The applicant is responsible for service and publication of required notices, including any related costs.

A. If the application is for an Oil and Gas Development Plan, the Operator must comply with the notice provisions of Rule 303.e. prior to a hearing on the Plan.

(2) No later than 30 days before the noticed hearing date, the applicant will submit to the Secretary:

A. A certificate of service demonstrating that the applicant served a copy of the application and notice on all persons entitled to notice pursuant to the Commission's Rules. The certificate of service will include a list of all persons who received a copy of the application and notice.

B. A notarized affidavit providing assurance that the applicant published a copy of the notice in a newspaper of general circulation in the county where the land affected is situated, and the date of publication for each newspaper used. The applicant is not required to submit a notarized proof of publication from the newspapers, or copies of the publications, unless a concern with publication is raised. Service of process by publication to unknown addresses will occur through five weeks of publication ending at the Rule 507 petition deadline, at least 30 days prior to the noticed hearing date.

(3) Notice by publication or notice by electronic mail provided pursuant to this subsection does not confer Affected Person status on any person.

b. Notice for specific applications.

(1) **Applications for Oil and Gas Development Plans.** Oil and Gas Development Plan applications will be served on all persons identified in Rule 303.d.(2) and 303.e.(1).

(2) **Applications related to drilling units.** For purposes of applications for drilling units, additional wells within existing drilling units or other applications for modifications of, or exceptions to, existing drilling unit orders (except for applications for well exception locations to existing orders which are addressed in subsection (6) of this Rule) the application and notice will be served on the mineral Owners within the proposed drilling unit or within the existing drilling unit to be affected by the applications. The persons identified in Rule 303.d.(2) must also receive notice of such an application.

(3) **Applications for involuntary pooling.** For purposes of applications for involuntary pooling orders made pursuant to § 34-60-116, C.R.S., the application and notice will be served on those persons who own any interest in the mineral estate, whether leased or unleased, of the tracts to be pooled, except Owners of an overriding royalty interest.

(4) **Applications for unitization.** For purposes of applications for unitization made pursuant to § 34-60-118, C.R.S., the application and notice will be served on those persons who own any interest in the mineral estate underlying the tract or tracts to be unitized and the Owners within one-half mile of the tract or tracts to be unitized. The Relevant Local Governmental Designee, Proximate Local Government, the Colorado Department of Public Health and Environment, and the Colorado Division of Parks and Wildlife must also receive notice of this application.

(5) **Applications changing certain well location setbacks.** For purposes of applications that change the permitted minimum setbacks for drilling and spacing units, the application and notice will be served on those Owners of contiguous or cornering tracts who may be affected by such change.

(6) **Applications for well location exception.** For purposes of applications made for exceptions to 401.a and 401.b granted pursuant to Rule 401.c., exceptions to legal locations within drilling and spacing units, or for an exception location to an existing order, the application and notice will be served on the Owners of any contiguous or cornering tract upon which the well location is encroaching, provided that when the applicant owns any interest covering such tract, the person who owns the mineral estate underlying the tract covered by such lease will also be notified.

(7) **All other applications.** For any application not specified above, the Secretary has discretion to determine who is entitled to receive the application and notice, based on legal interest and potential impact.

(8) **Orders related to violations.** With respect to the resolution of a Notice of Alleged Violation (NOAV) the application and notice will be provided to a relevant complainant (if any), to the alleged violator or alleged responsible party, or Operator, as applicable; and by publication in accordance with § 34-60-108(4), C.R.S.

c. **Notice to the Colorado State Board of Land Commissioners.** The application and notice will also be given to the Colorado State Board of Land Commissioners for all applications where the Colorado State Board of Land Commissioners maintains a mineral Ownership included in the application lands.

d. **Notice to Colorado Parks and Wildlife.** The application and notice will also be given to Colorado Parks and Wildlife for all applications where Colorado Parks and Wildlife maintains a mineral Ownership included in the application lands.

e. **Notice to Tribal Governments.** The application and notice will also be given to the Southern Ute Indian Tribe or the Ute Mountain Ute Tribe for all applications involving minerals within the exterior boundary of either tribe's reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Tribe.

f. **Notice to the Bureau of Land Management.** The application and notice will also be given to the Bureau of Land Management for all applications where the Bureau of Land Management maintains or manages a mineral or surface Ownership included in the application lands.

505. EVIDENCE IN SUPPORT OF AN APPLICATION

a. Applicants seeking relief under Rule 503.g.(1)–(3), and (5)-(6) will submit the documents described in (1) through (6) below to the Commission with its application. The Commission, Administrative Law Judge, or Hearing Officer will determine if additional evidence is needed on a case-by-case basis. If the application lacks sufficient information or evidence, the application may be continued at the Commission, Administrative Law Judge, or Hearing Officer's discretion.

(1) Sworn written testimony, of relevant witnesses verifying land, geologic, engineering, public health, safety, welfare, environment and wildlife facts, or such other facts and testimony as may be required by the Commission's Rules. Geologic and engineering written testimony are not required for Rule 503.g.(3) applications. Such testimony will be accompanied by attachments or exhibits that adequately support and is specific to the relief requested in the application, along with resumes/curricula vitae for each witness;

(2) A statement, signed under oath, from a person having knowledge of the stated facts, attesting to the facts stated in the written testimony and any attachments or exhibits. The sworn statement need not be notarized, but it will contain language indicating that the signatory is affirming that submitted testimony and supporting documents are true and correct to the best of the signatory's knowledge and belief and, if applicable, that they were prepared by the signatory or under the signatory's supervision;

(3) A sworn statement that is a summary of the testimony to support the relief requested in the application, including a request to take administrative notice of repetitive general, technical, or scientific evidence, where appropriate;

(4) 1 set of exhibits which will contain relevant highlights in bullet-point format on each exhibit; and

(5) A draft proposed order, if requested by the Administrative Law Judge, or Hearing Officer, with findings of fact and conclusions of law related to land, geology, engineering, public health, safety, welfare, environment and wildlife and other appropriate subjects to support the relief requested in the application. Geologic and engineering evidence are not required for a Rule 503.g.(3) orders.

Reference to testimony, exhibits, and previous Commission orders will be included as findings in the draft proposed order.

b. Applications for exception locations will include the information required in Rule 401.c.

506. INVOLUNTARY POOLING APPLICATIONS

a. An application for involuntary pooling pursuant to § 34-60-116, C.R.S., may be filed at any time by an Owner who owns, or has secured the consent of the Owners of, more than 45 percent of the mineral interests to be pooled within a drilling and spacing unit established by Commission order, prior to or after drilling of a well, but no later than 90 days in advance of the date the matter is to be heard by the Commission, as per Rule 510.a. Mineral interests that are owned by a person who cannot be located by the applicant through reasonable diligence are not included for purposes of determining whether the 45 percent mineral interests threshold is met.

b. The Commission must receive evidence that Owners were tendered a good faith, reasonable offer to lease or participate no less than 90 days prior to an involuntary pooling hearing. An application for involuntary pooling may be filed concurrently with the sending of a good faith, reasonable offer to lease or participate. While an application for involuntary pooling may be filed at any time prior to or after the drilling of a well, any involuntary pooling order issued will be retroactive to the date the application is filed with the Commission unless the payor agrees otherwise.

(1) For purposes of this Rule 506, "good faith" means a state of mind consisting in observance of reasonable commercial standards of fair dealing in oil and gas operations, and absence of intent to defraud or seek unconscionable advantage.

c. Upon a showing by the applicant that it has complied with the Commission's Rules, the Commission may deem an Owner to be a nonconsenting Owner in the area to be pooled if:

(1) After receiving an offer to participate and given at least 60 days to review the offer, the Owner does not elect in writing to consent to participate in the cost of the well concerning which the pooling order is sought. The offer to participate must include the following information, at a minimum:

A. The location and objective depth of the well.

i. Directional wells will include the estimated Measured Depth and True Vertical Depth (MD, TVD), and

ii. Horizontal wells will include the estimated Measured Depth, True Vertical Depth, and Lateral Length (MD, TVD, LL);

B. The estimated drilling and completion cost in dollars of the well (both the total cost and the Owner's share);

C. The estimated spud date for the well or range of time within which spudding is to occur; and

D. Contact information for an Operator representative who will be available to answer Owner questions.

(2) An authority for expenditure prepared by the Operator and containing the information required above, together with additional information deemed appropriate by the Operator may satisfy these obligations.

(3) If, after receiving a good faith offer to lease and given at least 60 days to review the offer, the unleased Owner has failed to accept or refused a reasonable offer to lease. In determining whether a good faith, reasonable offer to lease has been tendered under § 34-60-116(7)(d), C.R.S., the Commission will consider the lease terms listed below for the drilling and spacing unit in the application and for all cornering and contiguous units, and additional leases where necessary to obtain a representative sample of the lease market:

A. Date of lease and primary term or offer with acreage in lease;

B. Annual rental per acre;

C. Bonus payment or evidence of its non-availability;

D. Mineral interest royalty; and

E. Such other lease terms as may be relevant.

(4) for an offer to lease to be considered reasonable and have been made in good faith, the offer must be written in clear and neutral language and include information on which the offered price can be determined to be fair.

d. A nonconsenting Owner will be subject to cost recovery pursuant to § 34-60-116(7)(b), C.R.S.

e. All offers to lease or participate must include contact information for a representative of the applicant to answer questions and the Commission's brochure describing its pooling procedures and the Owner's options related to pooling.

507. CONTESTED HEARING APPLICATIONS

a. A person who may be affected or aggrieved by an application may submit a Petition to the Commission as an Affected Person to participate formally as a party in any adjudicatory proceeding. The Petition will set forth a brief and plain statement of the facts which entitle that person to be admitted and the matters which the person claim should be decided. The Commission, Hearing Officer, or Administrative Law Judge may admit any person or agency as a party to the proceeding for limited purposes.

(1) Governmental entities, including Relevant and Proximate Local Governments and public agencies with legal authority over issues contemplated by the application, are Affected Persons.

(2) For all persons other than those listed in Rule 507.a.(1), the person's petition must

A. Identify an interest in the activity that is affected by the proposed activity;

B. Allege such interest could be an injury-in-fact if the application is granted; and

C. Demonstrate that the injury alleged is not common to members of the general public.

(3) When determining if a person is an Affected Person all relevant factors will be considered, including, but not limited to, the following:

A. whether the interest claimed is one protected or affected by the application;

B. whether a reasonable relationship exists between the interest claimed and the activity regulated;

C. likely impacts, of the regulated activity on the health, safety, or use of property of the person;

D. likely impacts, of the regulated activity on use of the impacted natural resource or wildlife by the person; or

E. for Government Agencies not identified in 507.a.(1), its legal authority over or interest in the issues relevant to the application.

b. For purposes of an application filed pursuant to Rule 503.g.(2)-(3), only a mineral Owner within the unit, Relevant Local Government, Proximate Local Government, Colorado Department of Public Health and Environment or Colorado Division of Parks and Wildlife may file a petition.

c. A petition filed by the Relevant Local Government, Colorado Department of Public Health and Environment or Colorado Division of Parks and Wildlife will be granted.

d. The petition will be filed with the Commission, and served on the applicant's counsel, if the applicant is represented by counsel, at least 30 days before the hearing. If the applicant is not represented by counsel, service will be made on the applicant.

e. As per Rule 510.k. the filing deadline for the filing of petitions may be extended for good cause upon any continuance of a hearing.

f. All petitions will include:

(1) The application docket number;

(2) A general statement of the factual or legal basis for the petition based on the application;

(3) A statement and support for why the person filing the petition meets the definition of an Affected Person;

(4) A statement of the relief requested;

(5) A written description of the case the Affected Person plans to present to the Commission including a list of proposed witnesses;

(6) A time estimate to hear the petition; and

(7) A certificate of service attesting that the pleading has been served on the applicant and any other party in the proceeding.

g. The Commission, Administrative Law Judge, or Hearing Officer may require any additional information necessary pursuant to the Commission's Rules to ensure the petition is complete. The Commission, Administrative Law Judge, or Hearing Officer has the discretion to summarily dismiss without prejudice any petition that does not meet the informational requirements set forth in this Rule.

508. UNCONTESTED HEARING APPLICATIONS

a. If a matter is uncontested, the applicant may request approval without a hearing based on an Administrative Law Judge's or Hearing Officer's review of the merits of the verified application and the supporting exhibits. For purposes of this Rule an uncontested matter will mean any application is not subject to a petition objecting to the relief requested in the application and additionally will include matters in which all interested parties have consented in writing to the granting of the application without a hearing.

b. Uncontested applications recommended for approval by an Administrative Law Judge, or Hearing Officer may be of special interest to the Commission and may be recommended by the Director for presentation to the Commission.

509. PREHEARING PROCEDURES FOR CONTESTED APPLICATIONS

a. The Commission encourages the use of prehearing conferences between parties to a contested matter in order to facilitate settlement, narrow the issues, identify any stipulated facts, resolve any other pertinent issues, and reduce the hearing time. A prehearing conference will be conducted at the direction of the Commission, an Administrative Law Judge, or Hearing Officer upon receipt of a petition, an enforcement matter, or upon the request of the applicant or any person who has filed a petition. For matters in which staff is a party or a staff analysis has been prepared, the Director will participate in the prehearing conference to advise the parties of the content of staff's analysis. The prehearing conference will be conducted under the following general guidelines.

b. The Commission, Administrative Law Judge, or Hearing Officer will enter a case management order that establishes:

(1) The hearing schedule;

(2) The filing deadlines;

(3) Whether discovery is permitted; and

(4) Any other procedural matters.

c. An Administrative Law Judge, or Hearing Officer will preside over any prehearing conference and rule on preliminary matters.

d. The Secretary, Administrative Law Judge, or Hearing Officer will notify the applicant and any person who has filed a petition of the prehearing conference, and will direct the attorneys for the parties, and pro se parties, to appear in order to expedite the hearing or settle issues, or both.

e. All parties will be prepared to discuss all procedural and substantive issues and will be authorized to make binding commitments.

f. Preparation should include advance study of all materials filed and, if discovery is permitted pursuant to Rule 509.b.(3), such materials obtained through discovery.

g. Failure of a party to attend any hearing other than a rulemaking hearing, after being notified of the date, time, and place, will be a waiver of any objection and will be deemed to be a concurrence to any agreement reached, or to any order or ruling made at the hearing, including the entry of a default judgment or the dismissal of a petition.

h. A prehearing statement may be required of any party.

i. At any prehearing conference, the following matters may be considered:

(1) Offers of settlement or designation of issues;

(2) Simplification of and establishment of a list or summary of the issues;

(3) Bifurcation of issues for hearing purposes;

(4) Admissions as to, or stipulations of facts not remaining in dispute or the authenticity of documents;

(5) Limitation of the number of fact and expert witnesses;

(6) If a party seeks additional discovery beyond what was permitted by Rule 509.b.(3), a limitation on methods and extent of discovery, and a discovery schedule;

(7) Disposition of procedural motions; and

(8) Other matters raised by the parties, the Commission, Administrative Law Judge, or Hearing Officer.

j. At any prehearing conference, the following information may be required:

(1) An exchange and acceptance of service of exhibits proposed to be offered in evidence, and establishment of a list of exhibits to be offered;

(2) Establishment of a list of witnesses to be called and anticipated testimony times; and

(3) A timetable for the completion of discovery, if discovery is allowed.

k. The Administrative Law Judge, or Hearing Officer will reduce to writing any agreement reached or orders issued at a prehearing conference. The Administrative Law Judge, or Hearing Officer may require parties to submit proposed findings or orders.

l. It is the intent of this Rule 509 that a prehearing order will be binding upon the participating parties.

m. Subsequent to the prehearing conference and prior to the hearing on a contested matter, the parties may be asked to each prepare and submit to the Administrative Law Judge, or Hearing Officer a recommended order to consider for adoption at the time of hearing.

510. HEARINGS

a. No application may be heard until the applicant has complied with all notice, evidentiary and other application requirements set forth in the Commission's Rules.

b. A case management order, issued by the Commission, Administrative Law Judge, or Hearing Officer, will govern all hearings, including rulemaking hearings.

c. Administrative hearings in uncontested applications.

(1) As to applications where there has been no petition filed with the Commission in accordance with Rule 507, and where the Administrative Law Judge, or Hearing Officer has not issued a written recommended order approving the application, the application may be heard administratively. The date and time of the administrative hearing will be scheduled for the mutual convenience of the applicant and the Administrative Law Judge, or Hearing Officer. The administrative hearing may be conducted prior to the date a petition filed pursuant to Rule 507.d is filed, but no recommended order will issue until the Administrative Law Judge, or Hearing Officer has fully considered any timely and properly filed petition.

(2) An Administrative Law Judge, or Hearing Officer may hear the application at the administrative hearing. Administrative hearings will proceed informally in a meeting format. The applicant may present its case using exhibits and witnesses. All witnesses will be sworn. At the conclusion of the administrative hearing, the Administrative Law Judge, or Hearing Officer will make a decision concerning approval or denial of the application and so inform the applicant. The Administrative Law Judge, or Hearing Officer will put such decision in a written report to the Commission containing findings of fact, conclusions of law, if any, and a recommended order. If the Administrative Law Judge, or Hearing Officer's recommended order is a denial or qualified approval of the application, the applicant will be entitled to file an exception.

d. Hearings in contested applications. Every party will have the right to present its case at hearing by oral and documentary evidence. A case management order, issued by the Commission, Administrative Law Judge, or Hearing Officer, will govern the hearing of a contested application.

e. Order Finding Violation hearing.

(1) An Order Finding Violation (OFV) hearing will be held before the Commission, Administrative Law Judge, or Hearing Officer when:

A. The enforcement matter cannot be resolved through an AOC;

B. For any enforcement actions governed by Rule 525.d.(1)

(2) OFV hearings for enforcement actions not governed by Rule 525.d.(1). are commenced by service of the NOAV and Notice and Application for Hearing. The Director is not required to file a separate application for an OFV hearing. An OFV hearing will commence on the date stated in the Notice and Application for Hearing, unless continued by the Commission, Administrative Law Judge, or Hearing Officer.

(3) The Commission may commence an OFV hearing on its own motion, with notice pursuant to Rule 504., if it believes the Director has failed to enforce a provision of the Act, or a Commission Rule, order, or permit.

(4) OFV hearings are *de novo* proceedings.

f. Hearing on Complainant's Petition for Review.

(1) The Commission's hearing on a complainant's Petition for Review pursuant to Rule 524.c. will be limited to evidence and information entered into the record prior to the Director's contested decision, and any evidence or information received and considered by the Director following an order from the Commission, Administrative Law Judge, or Hearing Officer. No party to the Petition for Review hearing may present evidence or information that was not previously presented to the Director.

(2) It is the complainant's burden to show the Director's action was clearly erroneous.

A. If the Commission, Administrative Law Judge, or Hearing Officer finds that the Director's action was clearly erroneous, they may remand the matter to the Director for further proceedings, or order other such relief deemed just and reasonable.

B. If the complainant fails to meet its burden, the Commission, Administrative Law Judge, or Hearing Officer will deny the Petition for Review, and act on the final proposed AOC pursuant to Rule 523.d.(1)C.

g. Rulemaking Hearings. All rulemaking proceedings will be held in accordance with Rule 529.

h. Witnesses. Any witness at a hearing will take an oath or affirmation before testifying. After a witness has testified, the applicant, the petitioner, and any Commissioner may cross-examine that witness in the order established by the chairperson of the Commission. If the hearing is before an Administrative Law Judge, or Hearing Officer, the Administrative Law Judge, or Hearing Officer may ask questions during or after witness testimony or, cross-examine the witness.

i. Limitations of testimony.

(1) Testimony and cross-examination by a petitioner will be limited to those issues that reasonably relate to the interests that the petitioner seeks to protect, and which may be adversely affected by an order of the Commission, as determined by the Commission, Administrative Law Judge, or Hearing Officer.

(2) Where two or more petitioners have substantially similar interests and positions, the Commission, Administrative Law Judge, or Hearing Officer may limit cross-examination or argument on motions and objections to fewer than all petitioners. The Commission may also limit testimony to avoid undue delay, waste of time or needless presentation of cumulative evidence.

j. **Closing of record.** At the conclusion of closing statements, the record will be closed to the presentation of any further evidence, testimony, or statements, except as such may occur in response to questions from the Commission, Administrative Law Judge, or Hearing Officer.

k. The Commission, Secretary, Administrative Law Judge, or Hearing Officer may for good cause cancel, stay, or continue any hearing to another date. Upon continuance of a hearing, the deadline for filing a petition to contest an application under Rule 507., or any other required deadline under the Commission's Rules, maybe extended for good cause by the Commission, Administrative Law Judge, or Hearing Officer.

l. When a Commission hearing is scheduled for multiple days the Secretary may estimate the time and date that a given matter may be heard by the Commission. The Commission may, in its discretion, change the proposed hearing docket, including the time or date of any scheduled hearing. It will be the responsibility of the participating parties and attorneys to be present when the Commission hears the matter.

511. LOCAL PUBLIC HEARING.

a. A Relevant Local Government, Proximate Local Government or tribal authority may request the Commission hold a Local Public Hearing to gather feedback from the local community, including elected officials and local government officials, on a proposed Oil and Gas Development Plan or Comprehensive Area Plan. The Commission will decide whether to grant all requests for a Local Public Hearing. The Commission has discretion to decline a request for a Local Public Hearing, or in the alternative hold the local public hearing at the Commission's offices. The Commission may choose to hold a Local Public Hearing on its own motion.

b. A request for a local public hearing must be in writing, and must include the docket number for the relevant Plan. The request for a local public hearing must state with reasonable specificity the reasons why the Commission should hold a local public hearing.

c. The conduct of a local public hearing will be informal, and participants will not be required to be sworn in prior to making a statement, represented by attorneys, or subjected to cross examination.

d. The applicant may participate in the local public hearing and present information related to the application.

e. The Director will create a record of the local public hearing by video-tape, audio-tape, or court reporter. Such record will be available to all Commissioners for review prior to the hearing on the Plan application.

f. Issues raised in a local public hearing may include any topic relevant to the Plan.

512. PUBLIC COMMENT

a. The Commission may accept oral or written comments from the public about any matter during a time specified for general public comment by the Commission.

b. If the Commission receives public comments concerning an adjudicatory proceeding to be heard by the Commission, the public comments will be included in the administrative record for the adjudicatory proceeding.

c. Parties to a proceeding may not provide public comment in that proceeding; they are not considered part of the public for comment purposes.

513. COMMISSION MEMBERS REQUIRED FOR HEARINGS AND/OR DECISIONS

A quorum of the voting members of the Commission is required for the transaction of business. Testimony may be taken and oath or affirmation administered by any member of the Commission, or by counsel to the Commission if the Commission Chair so delegates.

514. STANDARDS OF CONDUCT

a. The purpose of this Rule 514. is to ensure that the Commission's decisions are free from personal bias and that its decision-making processes are consistent with the concept of fundamental fairness. The provisions of this Rule 514 are in addition to the requirements for Commission members set forth in § 24-18-108.5, C.R.S. This Rule 514 should be construed and applied to further the objectives of fair and impartial decision making. To achieve these standards Commissioners, Administrative Law Judges, and Hearing Officers should:

(1) Discharge their responsibilities with high integrity.

(2) Respect and comply with the law. Their conduct, at all times, should promote public confidence in the integrity and impartiality of the Commission.

(3) Not lend the prestige of the office to advance their own private interests, or the private interests of others, nor should they convey, or permit others to convey, the impression that special influence can be brought to bear on them.

b. **Conflicts of interest.** A conflict of interest exists in circumstances where a Commissioner, Administrative Law Judge, or Hearing Officer has a personal or financial interest that prejudices that person’s ability to participate objectively in an official act.

(1) A Commissioner, Administrative Law Judge, or a Hearing Officer will disclose the basis for a potential conflict of interest to the Commission and others in attendance at the hearing before any discussion begins or as soon thereafter as the conflict is perceived. A conflict of interest may also be raised by other Commissioners, the applicant, any petitioner, any parties to the proceeding, or any member of the public.

(2) In response to an assertion of a conflict of interest, a Commissioner may withdraw or the Director may designate an alternate Administrative Law Judge, or Hearing Officer. If the Commissioner does not agree to withdraw, the other Commissioners will vote on whether a conflict of interest exists. Such vote will be binding on the Commissioner with the conflict.

(3) In determining whether there is a conflict of interest that warrants withdrawal, the Commission members, Administrative Law Judge, or Hearing Officer will take the following into consideration:

A. Whether the official act will have a direct economic benefit on a business or other undertaking in which the Commissioner, Administrative Law Judge, or Hearing Officer has a direct or substantial financial interest.

B. Whether the potential conflict will result in the Commissioner, Administrative Law Judge, or Hearing Officer not being capable of judging a particular controversy fairly on the basis of its own circumstances.

C. Whether the potential conflict will result in the Commissioner, Administrative Law Judge, or Hearing Officer having an unalterably closed mind on matters critical to the disposition of the proceeding.

c. Discharge of duties. In the performance of its official duties, the Commission will apply the following standards:

(1) To be faithful to and constantly strive to improve its competence in statutory and regulatory principles, and to be unswayed by partisan interests, public clamor, or fear of criticism.

(2) To maintain order and decorum in the proceedings before it.

(3) To be patient, dignified and courteous and to require similar conduct of attorneys, staff, and others subject to its direction and control.

(4) To afford to every person who is legally interested in a proceeding full right to be heard according to law.

(5) To diligently discharge its administrative responsibilities, maintain professional confidence in Commission administration, and facilitate the performance of the administrative responsibilities of other staff officials.

515. REPRESENTATION AT ADMINISTRATIVE AND COMMISSION HEARINGS

a. Natural persons may appear on their own behalf and represent themselves at hearings before the Commission, and persons allowed to make oral or written statements may do so without counsel. Participants who are not represented by legal counsel are subject to the Commission's Rules.

b. Except as provided in subsections a. and c. of this Rule 515., representation at hearings before the Commission will be by attorneys licensed to practice law in the State of Colorado. Any attorney duly admitted to practice law in a court of record of any state or territory of the United States or in the District of Columbia, but not admitted to practice in Colorado, who appears at a hearing before the Commission may, upon motion, be admitted for the purpose of that hearing only, if that attorney has associated for purposes of that hearing with any attorney who:

(1) Is admitted to practice law in Colorado; and

(2) Is a resident or maintains a law office within Colorado;

c. The Commission has the discretion to allow representation by a corporate officer or director of a community organization, a closely held entity, a citizens' group duly authorized under Colorado law, or if a limited liability corporation, the member or manager in the following circumstances:

(1) Rulemakings;

(2) Local public hearings; or

(3) When an individual is appearing on behalf of a closely held corporation as provided in § 13-1-127, C.R.S.

d. Unless a non-attorney is appearing pro se or pursuant to § 13-1-127, C.R.S., or the Director is participating pursuant to Rule 510.e. or 510.f., a non-attorney will not be permitted to examine or cross-examine witnesses, make objections or resist objections to the introduction of testimony, or make legal arguments.

516. SUBPOENAS

The Commission, Administrative Law Judge, or a Hearing Officer may issue subpoenas requiring attendance of witnesses and the production of books, papers, and other instruments to the same extent and in the same manner and in accordance with the Colorado Rules of Civil Procedure. A party seeking a subpoena will submit the form of the subpoena for execution. Upon execution, the party requesting the subpoena has the responsibility to serve the subpoena in accordance with the Colorado Rules of Civil Procedure.

517. APPLICABILITY OF COLORADO COURT RULES AND ADMINISTRATIVE NOTICE

a. The Colorado Rules of Civil Procedure apply to Commission proceedings unless they are inconsistent with Commission Rules or the Act, or as the Administrative Law Judge, or Hearing Officer may otherwise direct on the record during prehearing proceedings or by written order.

b. In general, the Colorado Rules of Evidence applicable before a trial court without a jury will be applicable in matters before the Commission, providing that such rules may be relaxed, where, by so doing, the ends of justice will be better served.

(1) To promote uniformity in the admission of evidence, the Commission, Administrative Law Judge, or Hearing Officer to the extent practical, will observe and conform to the Colorado Rules of Evidence applicable in civil non-jury cases in the district courts of Colorado.

(2) When necessary to ascertain facts affecting substantial rights of the parties to a proceeding, the Commission, Administrative Law Judge, or Hearing Officer may receive and consider evidence not admissible under the Rules of Evidence, if the evidence possesses probative value commonly accepted by reasonable and prudent persons in the conduct of their affairs.

(3) Informality in any proceeding or in the manner of taking testimony will not invalidate any Commission order, decision, rule, or regulation.

c. **Administrative notice.** The Commission, Administrative Law Judge, or Hearing Officer may take administrative notice of:

(1) Constitutions and statutes of any state, tribe, and of the United States;

(2) Rules, regulations, official reports, decisions, and orders of local, state and federal administrative agencies;

(3) Decisions and orders of federal and state courts;

(4) Commission and Commission staff reports, data, files, documents, and records;

(5) Matters of common knowledge and undisputed technical or scientific fact;

(6) Matters that may be judicially noticed by a Colorado district court in a civil case; and

(7) Matters within the expertise of the Commission or Commission staff

d. Upon receipt of an objection to any discovery issued under Rule 509.b.(3), the Commission, Administrative Law Judge, or a Hearing Officer has the discretion to limit the scope of the discovery sought to matters that are within the scope of the Commission's jurisdiction under the Act, or otherwise

518. ELECTRONIC FILING

a. All applications, pleadings, petitions or documents filed pursuant to the Commission's Rules will be submitted electronically in a manner determined by the Director.

b. All applications, pleadings, petitions or documents filed pursuant to the Commission's Rules will be accompanied by a docket fee established by the Commission (see Appendix III). No docket fees will be assessed on filings made by Commission staff, or governmental agencies. The docket fee will be refunded if a petition is denied. In cases of hardship, the docket fee may be waived at the discretion of the Director or the Commission.

519. CONSENT AGENDA

a. Regular hearings will be held before the Commission on such days as may be set by the Commission.

b. The Secretary may place on the consent agenda those uncontested matters recommended by an Administrative Law Judge, or Hearing Officer for approval if a recommended order has not become the final agency action pursuant to Rule 520.b.

(1) All matters on the consent agenda may be presented individually or in groups. All matters within a group will be voted on together, without deliberation and without the necessity of reading into the record the individual items. However, any Commissioner may request clarification from the Director or from the attorney or other representative of the applicant for any matter on the consent agenda.

(2) Any Commissioner may remove a matter from the consent agenda prior to voting thereon.

(3) Any matter removed from the consent agenda will be heard at the end of the remaining agenda, if practicable and agreeable to the applicant, or, if not, scheduled for hearing at the next regularly scheduled meeting of the Commission.

520. DECISIONS, ORDERS AND EXCEPTIONS

a. Interim Decisions.

(1) Interim decisions are issued after an application is set for hearing, but are not recommended orders that may become a final decision of the Commission. A Hearing Officer or Administrative Law Judge's decision on a motion to dismiss or petition to be a party is an interim decision unless an application is dismissed in its entirety.

(2) Interim decisions will not be subject to exceptions. However, any aggrieved party or rulemaking participant may challenge the matters determined in an interim decision in exceptions to a recommended order.

(3) Nothing in this Rule 520.a. prohibits a motion for clarification of an interim decision set forth in an interim decision.

b. Recommended Orders. After due consideration of written statements, oral statements, the testimony, the evidence, and the arguments presented at hearing, the Administrative Law Judge, or Hearing Officer will make a written recommended order based upon evidence in the record, consistent with the Act and any Commission Rule, permit, or order made pursuant thereto. The Administrative Law Judge, or Hearing Officer will promptly transmit electronically to the Commission and the parties the record and exhibits of the proceeding and a written recommended order. The recommended order becomes a final agency action if no exceptions are filed within 20 days after service upon the parties and the Commission does not stay the recommended order on its own motion. The recommended order will also be served on any persons whose petition to participate in the matter was denied.

c. Exceptions. As per § 34-60-108(9), C.R.S., a recommended order becomes the Commission's final order unless, within 20 days or such additional time as the Commission may allow, any party or person whose petition to participate in the matter was denied files exceptions to the recommended order or the Commission orders the recommended order to be stayed. A stay of a recommended order does not automatically extend the period for filing exceptions or a motion for an extension of time to file exceptions. If exceptions are timely filed, the recommended order is stayed until the Commission rules upon them. Parties may file responses to exceptions within 14 days following service of the exceptions.

(1) The Commission will conduct a review upon the same record before the Administrative Law Judge, or Hearing Officer, and a de novo review of the law.

(2) The Commission may, upon its own motion or upon the motion of a party, order oral argument regarding exceptions. The Secretary will set the time allotted for argument. The Commission may terminate argument whenever, in its judgment, further argument is unnecessary. The party filing exceptions is entitled to open and conclude the argument. Arguments will be limited to issues raised in the exceptions, unless the Commission orders otherwise.

d. An Administrative Law Judge's or Hearing Officer's recommended order will be an initial decision for purposes of filing an exception pursuant to the state Administrative Procedure Act.

521. COMMISSION FINDINGS AND ORDER

a. After due consideration of written statements, oral statements, the testimony, and the arguments presented at hearing before the Commission, the Commission will make its findings and written order, based upon evidence in the record and, as appropriate, consistent with the Act and any Commission Rule, permit, or order made pursuant thereto.

b. Commission orders will be entered within 30 days after the hearing, as per § 34-60-108(7), C.R.S. Orders will be final upon Commission approval, and effective for purposes of judicial review on the date of electronic delivery or mailing.

522. SERVICE

a. A person filing any application, petition, pleading or other document will serve a copy, including all supporting attachments or exhibits, on every other party in the docketed matter. Service of all pleadings or other documents will be accomplished electronically in a manner determined by the Director.

b. Enforcement Documents. The Director will serve a Notice of Alleged Violation, a Notice of Hearing of an enforcement action or an OFV on the Operator or the Operator's designated agent and other parties as necessary by personal delivery or by certified mail, return receipt requested, to the address the Operator has on file with the Commission pursuant to Rule 447. All other documents in enforcement cases will be served electronically in a manner determined by the Director.

c. Complainant. Notice to a complainant may be served by confirmed electronic mail (unless previously objected to by a party) or by first class mail to the address provided. Where notice is sent electronically, notice is perfected when sent. Where notice is sent by first class mail, notice is perfected 5 days after mailing.

d. Petitions for Review. A Petition for Review by a complainant will be served on the Operator or the Operator's designated agent to the address on file with the Commission electronically in a manner as determined by the Director. If the complainant is unable to serve the Petition for Review electronically, the complainant will serve it by certified mail, return receipt requested. A complainant must serve its Petition for Review on the Operator within 7 days following filing of the Petition. All other documents in a Petition for Review proceeding will be served on all parties electronically (unless previously objected to by a party).

e. Cease and Desist Orders. In emergency situations, a Cease and Desist Order may be served electronically in a manner as determined by the Director, followed by a copy served on the Operator or the Operator's designated agent by personal delivery or by certified mail, return receipt requested, to the address the Operator has on file with the Commission pursuant to Rule 447. In non-emergency situations, a Cease and Desist Order may be served by certified mail.

f. Service by Certified Mail. When service is accomplished through certified mail it will be perfected at the earliest of:

(1) The date of receipt;

(2) The date shown on the return receipt; or

(3) 5 days after mailing.

g. Service by First Class Mail. If a party or person lacks access to file or receive documents electronically in a manner as determined by the Director, service will be made by first class mail. When service is accomplished through first class mail it is perfected 5 days after mailing. Service by first class mail may not be substituted for service by certified mail when service by certified mail is required by Commission Rule or the Act.

523. ENFORCEMENT

a. Identification of Alleged Violations. If, on the Director's own initiative or based on a complaint, reasonable cause exists to believe that a violation of the Act, any Commission Rule, order, or permit has occurred, the Director will require the Operator to remedy the violation and may commence an enforcement action by issuing a Notice of Alleged Violation (NOAV). Reasonable cause requires, at least, evidence of the alleged violation, as verified by the Director.

b. Resolution of Alleged Violations without Penalties.

(1) When the Director has reasonable cause to believe a violation of the Act, any Commission Rule, order, or permit has occurred, the Director may resolve the alleged violation without seeking a penalty if all of the following apply:

A. The Commission Rule allegedly violated is not a Class 3 rule and the degree of actual or threatened impact is minor or moderate under the Commission’s Penalty Schedule, Rule 525.c.(1);

B. The Operator has not received a previous Warning Letter or Corrective Action Required Inspection Report regarding the same violation;

C. The Director determines the alleged violation can be corrected without undue delay; and

D. The Operator timely performs all corrective actions required by the Director and takes any other actions necessary to promptly return to compliance.

(2) The Director retains discretion to seek penalties for any violation of the Act, or a Commission Rule, order, or permit, even if all of the factors in subpart 523.b. apply.

c. Enforcement Actions Seeking Penalties for Alleged Violations. When the Director determines that Rule 523.b.(1) does not apply or otherwise elects to seek penalties for an alleged violation, the Director will commence an enforcement action by issuing a Notice of Alleged Violation (NOAV).

(1) **Content of an NOAV.** An NOAV will identify the provisions of the Act, or Commission Rules, orders, or permits allegedly violated and will contain a short and plain statement of the facts alleged to constitute each alleged violation. The NOAV may propose appropriate corrective action and an abatement schedule required by the Director to correct the alleged violation.

(2) **Answer.** An answer to an NOAV must be filed within 28 days of the Operator's receipt of an NOAV, unless an exception or extension is granted by the Director. An answer will, at a minimum, discuss the allegations contained in the NOAV, responding to each; identify corrective actions taken in response to the NOAV, if any; and identify facts known to the Operator at the time that are relevant to the Operator's response to the alleged violations. If the Operator fails to file an answer within 28 days, the Director may request the Commission, Administrative Law Judge, or Hearing Officer enter a default judgment.

(3) **Procedural matters**.

A. Service of an NOAV constitutes commencement of an enforcement action or other proceeding for purposes of § 34-60-115, C.R.S.

B. Issuance of an NOAV does not constitute final agency action for purposes of judicial review.

C. A monetary penalty for a violation may only be imposed by Commission order.

d. **Resolution of Enforcement Actions.**

(1) **Administrative Order by Consent**. Except as provided in subpart 523.e.(2), an enforcement action is resolved upon the Commission's entry of an order approving an agreement between the Operator and the Director or by a recommended order becoming a final decision of the Commission.

A. A proposed agreement to resolve an enforcement action will be memorialized in an AOC executed by the Director and the Operator.

B. A complainant who has filed a written complaint on a Complaint Report, Form 18, will be informed of the terms of a draft proposed AOC resolving alleged violations arising directly out of their written complaint and will be given 14 days to comment on the draft settlement terms before the AOC is finalized and presented to an Administrative Law Judge, or Hearing Officer for a recommended order approving it. The Director will provide a copy of the final proposed AOC to the complainant. A complainant who objects to the final proposed AOC may file a Petition for Review pursuant to Rule 524.c.

C. AOCs that are not subject to a pending complainant's Petition for Review will be reviewed by an Administrative Law Judge, or Hearing Officer to issue a recommended order. A recommended order on an AOC becomes the decision of the Commission within 20 days after service upon the parties, unless the Commission stays the recommended order on the AOC within that time.

D. If the Commission stays the recommended order on the AOC, the Commission may

i. remand the matter to the Director for further proceedings; or

ii. direct the parties to appear before the Commission for hearing.

(2) **Orders Finding Violation.**

A. An enforcement action may not be resolved by the Director and must be heard by an Administrative Law Judge, or Hearing Officer, unless the Commission directs otherwise, when:

i. The Director alleges the Operator is responsible for gross negligence or knowing and willful misconduct that resulted in an egregious violation;

ii. The Director alleges the violation resulted in the death or serious injury of a person;

iii. The Director alleges the Operator has engaged in a pattern of violations; or

iv. The Commission sets an OFV hearing pursuant to Rule 510.e.(3).

e. **Rescinding an NOAV.** If, after issuance of an NOAV the Director no longer has reasonable cause to believe a violation of the Act, or of any Commission Rule, order, or permit occurred, the Director will rescind the NOAV in writing.

f. **Failure to Comply with Commission Orders.** An Operator's failure to diligently implement corrective action pursuant to an AOC, OFV, or other Commission order constitutes an independent violation which may result in an NOAV, additional penalties or corrective action requirements.

524. COMPLAINANT ENFORCEMENT MATTERS.

a. Any person may make a complaint using the Complaint Report, Form 18, to the Director alleging that a violation of the Act, any Commission Rule, order, or permit has occurred. The Director will investigate all complaints made pursuant to this Rule to the extent the Director believes sufficient grounds exist to warrant an investigation.

b. The Director will notify the complainant of whether an investigation will be conducted.

(1) If the Director determines no violation occurred, the Director will notify the Operator and the complainant, and no further action will be taken.

(2) If the Director determines a violation may have occurred, the Director may initiate and resolve the enforcement action in accordance with Rule 523.

(3) If a complaint specifically results in the issuance of an NOAV, a complainant who has filed a written complaint on a Complaint Report, Form 18, will be given 14 days to comment on the terms of a draft proposed settlement of the NOAV, if any, before the AOC is signed and presented to an Administrative Law Judge, or Hearing Officer for a recommended order approving it.

c. A complainant who has filed a written complaint on a Complaint Report, Form 18 may file a Petition for Review requesting the Commission hear the complainant's objections to:

(1) The Director's decision not to issue an NOAV for an alleged violation specifically identified in the written complaint; or

(2) The settlement terms of a final proposed AOC that settles an alleged violation arising directly from the Complaint Report, Form 18.

d. Complainants must file a Petition for Review application with the Commission within 28 days of service of the Director's decision.

e. A Petition for Review will set forth in reasonable detail the legal arguments and facts the complainant contends demonstrate that the Director's decision was clearly erroneous.

(1) A Petition for Review may include a request for a continuance of the enforcement hearing on the AOC. Such a request will be based on actual, compelling evidence, which has been gathered by the complainant after the Director's contested decision, and will explain why the Director should further investigate the circumstances surrounding the alleged violation. The Commission, an Administrative Law Judge, or Hearing Officer will determine whether a continuance is warranted, and whether to direct staff to conduct additional investigation or receive and consider additional information.

(2) An Administrative Law Judge, or Hearing Officer will issue a case management order that establishes the deadlines for filing responses to the Petition for Review.

(3) Discovery will not be permitted prior to the Petition for Review hearing.

f. Unless otherwise continued, a Petition for Review will be heard within 42 days following filing of the Petition for Review.

525. ASSESSING PENALTIES IN ENFORCEMENT MATTERS

a. **General.** If the Commission finds that an Operator has violated the Act, or a Commission Rule, order, or permit, the Commission may issue an order imposing a penalty. Penalties will be calculated based on the Act and this Rule 525. The Commission's Enforcement Guidance and Penalty Policy also provides non-binding guidance to the Commission and interested persons evaluating a penalty for an alleged violation.

b. **Days of Violation.** The duration of a violation presumptively will be calculated in days as follows:

(1) A reporting or other minor violation not involving actual or threatened significant adverse impacts begins on the day that the report should have been made or other required action should have been taken, and continues until the report is filed or the required action is commenced to the Director's satisfaction.

(2) All other violations begin on the date the violation was discovered or should have been discovered through the exercise of reasonable care and continue until the appropriate corrective action is commenced to the Director's satisfaction.

(3) With respect to violations that result in actual or threatened adverse impacts to public health, safety, and welfare, including the environment and wildlife resources, commencing appropriate corrective action includes, at a minimum:

A. Performing immediate actions necessary to assess and evaluate the actual or threatened adverse impacts; and

B. Performing all other near-term actions necessary to stop, contain, or control actual or threatened adverse impacts in order to prevent, minimize, or mitigate adverse impacts to public health, safety, and welfare, including the environment and wildlife resources. Such actions may include, without limitation, stopping or containing a spill or release of E&P Waste; establishing well control after a loss of control event; removing E&P Waste resulting from surface spills or releases; installing fencing or other security measures to limit access (including wildlife access) to affected areas; providing alternative water supplies; notifying affected landowners, local governments, and other persons or businesses; and, in cases of actual adverse impacts, mobilizing all resources necessary to fully and completely remediate the affected environment.

(4) A penalty will be assessed for each day the evidence shows a violation continued.

(5) The number of days of violation does not include any period necessary to allow the Operator to engage in good faith negotiation with the Commission regarding an alleged violation if the Operator demonstrates a prompt, effective, and prudent response to the violation.

c. **Penalty Calculation.** The base penalty for each violation will be calculated based on the Commission's Penalty Schedule which considers the severity of the potential consequences of a violation of a specific rule combined with an assessment of the degree of actual or threatened adverse impacts to public health, safety, and welfare, including the environment and wildlife resources. Pursuant to § 34-60-121(1)(a), the maximum daily penalty cannot exceed $15,000 per day per violation.

(1) **Penalty Schedule.** The Commission's Penalty Schedule is set forth in the following matrix. The matrix establishes a daily penalty based on the classification of the rule violation (Class 1, 2, or 3) and the degree of actual or threatened adverse impact resulting from the violation (minor, moderate, or major).

		Rule Classification		
		Class 1: Paperwork or other ministerial rules, a violation of which presents no direct risk or threat of harm to public health, safety, and welfare, including the environment and wildlife resources.	Class 2: Rules related at least indirectly to protecting public health, safety, and welfare, including the environment and wildlife resources, a violation of which presents a possibility of distinct, identifiable actual or threatened adverse impacts to those interests.	Class 3: Rules directly related to protecting public health, safety, and welfare, including the environment and wildlife resources, a violation of which presents a significant probability of actual or threatened adverse impacts to those interests.
Degree of threatened or actual impact to public health, safety, welfare, the environment, or wildlife	Major: Actual significant adverse impacts	$5,000	$10,000	$15,000
	Moderate: Threat of significant adverse impacts, or moderate actual adverse impacts	$1,500	$5,000	$10,000
	Minor: No actual adverse impact and little or no threat of adverse impacts	$200	$2,500	$5,000

(2) **Degree of actual or threatened adverse impact.** The base penalty for a violation may be increased based on the degree of actual or threatened adverse impact to public health, safety, and welfare, including the environment and wildlife resources resulting from the violation. The Commission, Administrative Law Judge, or Hearing Officer will determine the degree of actual or threatened adverse impact to public health, safety, and welfare, including the environment and wildlife resources, based on the totality of circumstances in each case. The Commission, Administrative Law Judge, or Hearing Officer will consider the following, non-exclusive, list of factors in making its determination:

A. Whether and to what degree the environment and wildlife resources were adversely affected or threatened by the violation. This factor considers the existence, size, and proximity of potentially impacted livestock, wildlife, soil, water, air, and all other natural or environmental resources.

B. Whether and to what degree Waters of the State were adversely affected or threatened by the violation.

C. Whether and to what degree drinking water was adversely affected or threatened by the violation.

D. Whether and to what degree public or private property was adversely affected or threatened by the violation.

E. The quantity and character of any E&P waste or non-E&P waste that was actually or threatened to be spilled or released.

F. Whether any persons were harmed or whether there was a threat to the health, safety, and welfare of any persons.

G. Any other facts relevant to an objective assessment of the degree of adverse impact to public health, safety, or welfare, including the environment and wildlife resources.

(3) **Penalty Adjustments for Aggravating and Mitigating Factors.** The Commission, Administrative Law Judge, or Hearing Officer may increase a penalty up to the statutory daily maximum amount if it finds any of the aggravating factors listed in subpart A., below, exist. The Commission, Administrative Law Judge, or Hearing Officer may decrease a penalty if it finds that the violator cooperated with the Commission and other agencies with respect to the violation and that any of the mitigating factors listed in subpart B., below, exist.

A. Aggravating factors:

i. The violator acted with gross negligence or knowing and willful misconduct.

ii. The violation resulted in significant waste of oil and gas resources.

iii. The violation had a significant negative impact on correlative rights of other parties.

iv. The violator was recalcitrant or uncooperative with the Commission or other agencies in correcting or responding to the violation.

v. The violator falsified reports or records.

vi. The violator benefited economically from the violation, in which case the amount of such benefit will be taken into consideration.

vii. The violator has engaged in a pattern of violations.

viii. The violation led to death or serious injury.

B. Mitigating factors:

i. The violator self-reported the violation.

ii. The violator demonstrated prompt, effective and prudent response to the violation, including assistance to any impacted parties.

iii. The cause of the violation was outside of the violator's reasonable control and responsibility, or is customarily considered to be force majeure.

iv. The violator made a good faith effort to comply with applicable requirements prior to the Commission learning of the violation.

v. The cost of correcting the violation reduced or eliminated any economic benefit to the violator, excluding circumstances in which increased costs stemmed from non-compliance.

vi. The violator has demonstrated a history of compliance with the Act, and Commission Rules, orders, and permits.

(4) **Penalty adjustments based on duration of violation.** In its discretion, the Commission, an Administrative Law Judge, or Hearing Officer may decrease the daily penalty amounts for violations of long duration to ensure the total penalty is appropriate to the nature of the violation.

d. **Pattern of Violations, Gross Negligence, or Knowing and Willful Misconduct.**

(1) The Director will apply for an OFV hearing when the Director determines an Operator has:

A. Engaged in a pattern of violations;

B. Acted with gross negligence or knowing and willful misconduct that resulted in an egregious violation; or

C. Engaged in an activity that resulted in death or serious injury.

(2) If the Commission, Administrative Law Judge, or Hearing Officer finds after hearing that an Operator is responsible for the conduct described in Rule 525.d.(1), the Commission, Administrative Law Judge, or Hearing Officer may suspend an Operator's Certification of Clearance, withhold new drilling or oil and gas location permits, or both. Such suspension will last until such time as the violator demonstrates to the satisfaction of the Commission that the Operator has brought each violation into compliance and that any penalty assessed, which is not subject to judicial review, has been paid at which time the Commission may vacate the order.

(3) The Commission, Administrative Law Judge, or Hearing Officer will consider an Operator's history of violations of the Act, or Commission Rules, orders, or permits, and any other factors relevant to objectively determining whether an Operator has engaged in a pattern of violations. For an Operator's history of violations, the Commission, Administrative Law Judge, or Hearing Officer may only consider violations confirmed by Commission order through an AOC or OFV.

e. **Voluntary disclosure.**

(1) The Director may consider a penalty reduction for a violation of the Act, or any Commission Rule, order, or permit voluntarily disclosed by an Operator if:

A. The disclosure is made promptly after the Operator discovers the violation;

B. The Operator discovered the violation independent of, and unrelated to a COGCC inspection or an NOAV;

C. The Operator cooperates with the Director regarding investigation of the disclosed violation; and

D. The Operator has achieved or commits to achieve compliance within a reasonable time and pursues compliance with due diligence.

(2) The Director may not consider a penalty reduction if:

A. The disclosure is made for fraudulent purposes;

B. The disclosed violation is part of a pattern of violations; or

C. The disclosed violation was egregious and the result of the Operator's gross negligence or knowing and willful misconduct.

(3) If the Director determines that any of the factors in subpart (1) are not met or that the factors in subpart (2) are met, the Director may consider the fact that the Operator self-reported the violation as a mitigating factor under Rule 525.c.(3)B.(i).

f. **Public Projects.** In its discretion, the Commission, Administrative Law Judge, or Hearing Officer may allow an Operator to satisfy a penalty in whole or in part by a Public Project that the Operator is not otherwise legally required to undertake. The costs of the Public Project may offset the penalty amount dollar for dollar, or by some other ratio determined by the Commission. A Public Project must provide tangible benefit to public health, safety and welfare, or the environment or wildlife resources. The Commission favors Public Projects that benefit the persons or communities most directly affected by a violation, or that provide education or training to local government entities, first responders, the public, or the regulated community related to the violation.

g. **Payment of penalties.** An Operator will pay a penalty imposed by Commission order, by certified funds unless otherwise agreed to, within 30 days of the effective date of the order, unless the Commission grants a longer period or unless the Operator files for judicial appeal, in which event payment of the penalty will be stayed pending resolution of such appeal. An Operator's obligations to comply with the provisions of a Commission order requiring compliance with the Act, or Commission Rules, orders, or permits will not be stayed pending resolution of an appeal, except by court order.

526. **DETERMINATION OF RESPONSIBLE PARTY.** If the Director initiates an enforcement proceeding against an Operator, the Operator may raise as an affirmative defense that it is not the Responsible Party for the alleged violation. An alleged responsible party will have the burden to present sufficient evidence to the Commission, Administrative Law Judge, or Hearing Officer to determine responsible party status.

a. A hearing may be initiated on the Commission's own motion, upon application, or at the request of the Director to decide responsible party status upon at least 21 days' notice to the potentially responsible parties.

b. Potentially responsible parties will be those persons that have or should have submitted Registration for Oil and Gas Operation, Form 1, or that have or should have submitted financial assurance for oil and gas operations pursuant to requirements of the 700-Series Rules.

c. Potentially responsible parties will provide to the Commission, Director, Administrative Law Judge, or Hearing Officer such information as the Commission, Director, Administrative Law Judge, or Hearing Officer may reasonably require in making such determination.

d. If an Operator raises an affirmative defense that another person is the Responsible Party, the Operator raising the affirmative defense must identify the person alleged to be the Responsible Party, and provide that person with notice concurrent with filing an Answer to a Notice of Alleged Violation.

e. The Commission, Administrative Law Judge, or Hearing Officer will make the determination under this section without regard to any contractual or legal disputes between the parties regarding assignments of liability or other legal defenses.

f. Each responsible party will be liable only for a proportionate share of any costs imposed under this Rule and will not be held jointly and severally liable for such costs.

g. The Commission, Administrative Law Judge, or Hearing Officer will find responsible party status and mitigation liability if the responsible party conducted operations that resulted in or threatened to cause an adverse impact to public health, safety, welfare, the environment or wildlife resources or an adverse environmental impact to any air, water, soil, or biological resource based on the conduct of oil or gas operations in contravention of any then applicable provision of the Act or Commission Rule, or order of the Commission, or of any permit that threatens to cause, or actually causes, a significant adverse environmental impact to any air, water, soil, or biological resource.

527. PERMIT-RELATED PENALTIES

a. If the Commission determines, after a hearing, that an Operator failed to perform any required corrective action, or failed to comply with a Cease and Desist Order issued by the Commission or the Director with regard to violation of a permit provision, the Commission may issue an order suspending, modifying, or revoking a permit or permits authorizing the operation. The order will provide the condition(s) which must be met by the Operator for reinstatement of the permit(s). An Operator which is subject to an order that suspends, modifies, or revokes a permit or permits will continue the affected operations only for the purpose of bringing them into compliance with the permit(s) or modified permit(s), and will do so under the supervision of the Director. Once the condition for reinstatement has been met to the satisfaction of the Director and any fine not subject to judicial review or appeal has been paid, the Director will inform the Commission, and the Commission, if in agreement, will reinstate the permit(s).

b. Whenever the Commission or the Director has evidence that an Operator is responsible for a pattern of violation of any provision of the Act, or of any rule, permit, or order of the Commission, the Commission or the Director will issue a notice to such Operator to appear for a hearing before the Commission. If the Commission finds, after such hearing, that a knowing and willful pattern of violation exists, it may issue an order which will prohibit the issuance of any new permits to such Operator. When such Operator demonstrates to the satisfaction of the Commission that it has brought each of the violations into compliance and that any fine not subject to judicial review or appeal has been paid, such order denying new permits will be vacated.

528. CEASE AND DESIST ORDERS.

a. The Commission or the Director, may issue a Cease and Desist Order when an Operator's alleged violation of the Act, Commission Rule, order, or permit, or failure to take required corrective action or other authorized activity that creates an emergency situation. If the Cease and Desist Order is entered by the Director, it will be reported to the Commission not later than the next regularly scheduled Commission hearing, unless the matter is heard pursuant to the expedited procedure under § 34-60-121(5)(b), C.R.S.

b. The Cease and Desist Order will be served pursuant to Rule 522. within 7 days after it is issued.

c. The Cease and Desist Order will state the provisions of the Act, or Commission Rules, orders, or permits alleged to have been violated, and will contain a short and plain statement of the facts alleged to constitute the violation, the time by which the acts or practices cited are required to cease, and any corrective action the Commission or the Director elects to require of the Operator.

d. Any objection by an Operator of a Cease and Desist Order will be heard by the Commission pursuant to § 34-60-121(5)(b), C.R.S. An Operator's objection to a Cease and Desist Order will not stay the order pending a Commission hearing on the matter, unless the Operator obtains an injunction enjoining enforcement of the Cease and Desist Order.

e. After the issuance of a Cease and Desist Order, the Director may require amendment to or suspension of a permit associated with the Cease and Desist Order if necessary to protect public health, safety, welfare, the environment, and wildlife resources.

f. If an Operator fails to comply with a Cease and Desist Order, the Commission may request the attorney general to bring suit pursuant to § 34-60-109, C.R.S.

529. RULEMAKING PROCEEDINGS

a. **Initiation of rulemaking.** The Commission may initiate rulemaking on its motion or in response to an application filed by any person, including the Director. Whether to conduct a rulemaking lies within the discretion of the Commission. A rulemaking may address regulations statewide, or in a more limited geographic area such as a specific geologic basin or field.

b. **Applications for rulemaking.** Any person may petition the Commission to initiate rulemaking. All applications for rulemaking will contain the following information:

(1) The name, address, and telephone number of the person requesting the rulemaking;

(2) A copy of the rule proposed in the application and a general statement of the reasons for the requested rule;

(3) The Commission's statutory authority to enact the proposed rule; and

(4) A proposed statement of the basis and purpose for the rule.

c. **Notice of proposed rulemaking.** All rulemaking hearings of the Commission will be noticed by publication in the Colorado Register not less than 20 days prior to the hearing and as otherwise specified in the Administrative Procedure Act, § 24-4-103, C.R.S.

d. **Development of proposed rules.** Prior to the notice of proposed rulemaking, the Commission or Director will establish a representative group of participants with an interest in the subject of the rulemaking as provided by § 24-4-103(2), C.R.S. The Commission or Director may also use other means to gather information, including, but not limited to public forums, investigation by Commission staff, and formation of rulemaking teams. Commissioners may participate in such informal proceedings.

e. **Content of notice.** The notice will state the time, date, place, and general subject matter of the hearing to be held. It may include a statement indicating whether an informal public meeting will be held, the time, date, place, and general purpose of the meeting, any special procedures the Commission deems appropriate for the particular rulemaking proceeding and a statement encouraging public participation. The notice will state that the proposed regulations will be available upon request from the office of the Commission, and the date of availability. The notice will include a short and plain statement which summarizes the intended action and states generally the basis and purpose of the rules.

f. **The rulemaking hearing.** The Commission will hold a formal public hearing before promulgating any rules or regulations. At that hearing, the Commission will afford any person an opportunity to submit data, views or arguments. The Commission may limit such testimony or presentation of evidence, including oral testimony or presentations, at its discretion and may prohibit repetitive, irrelevant, or harassing testimony.

g. **Conduct of rulemaking hearings.**

(1) The Commission encourages any person to participate at rulemaking hearings. The times at which the public may participate will be determined at the discretion of the Commission. The Commission may, at its discretion, limit the amount of time a person may use to comment or make public statements. Oaths will not be required for public participation.

(2) The Commission encourages witnesses to make plain, brief, and simple statements of their positions. It also encourages submittal of written statements prior to hearing, with only an oral summary of such a statement at the hearing. In its discretion, the Commission may allow only prefiled written testimony and oral testimony or presentations at a rulemaking hearing.

(3) The order of presentation at a rulemaking hearing will be as established by the Commission at the hearing.

(4) The Commission has the discretion to continue rulemaking hearings by announcement at the rulemaking hearing without republishing the proposed rules.

530. EX PARTE COMMUNICATIONS

a. The following provisions will be applied in any adjudicatory proceeding before the Commission, Administrative Law Judge, or a Hearing Officer.

(1) No person will make or knowingly cause to be made to any member of the Commission, Administrative Law Judge, or a Hearing Officer an ex parte communication concerning the merits of a proceeding for which an application has been filed.

(2) No Commissioner, Administrative Law Judge, or Hearing Officer will make or knowingly cause to be made to any interested person an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.

(3) A Commissioner, Administrative Law Judge, or Hearing Officer who receives, or who makes, or knowingly causes to be made, a communication prohibited by this rule will place on the public record of proceeding:

A. All such written communications and any responses thereto; and

B. Memoranda stating the substance of any such oral communications and any responses thereto.

(4) Upon receipt of a communication knowingly made or knowingly caused to be made by a person in violation of this rule, the Commission, Administrative Law Judge, or a Hearing Officer may require the person to show cause why their claim or interest in the proceeding should not be dismissed, denied, or otherwise adversely affected on account of such violation.

(5) If staff is a party to an adjudicatory proceeding they are subject to the provisions of this Rule 515(a).

b. Oral or written communication with individual Commission members is permissible in a rulemaking proceeding. If such information is relied upon in final decision-making it will be made part of the record by the Commission. After the rulemaking record is closed new information that is intended for the rulemaking record will be presented to the Commission as a whole upon approval of a request to reopen the rulemaking record.

c. This rule will not limit the right to challenge a decision of the Commission, Administrative Law Judge, or a Hearing Officer on the grounds of bias or prejudice due to any ex parte communication.

100 SERIES

DEFINITIONS

GEOLOGIC HAZARD is defined in § 24-65.1-103, C.R.S.

NOXIOUS WEEDS is defined in § 35-5.5-103, C.R.S.

TANK means a stationary vessel constructed of non-earthen materials (e.g. concrete, steel, plastic) that provides structural support and is designed and operated to store produced fluids or E&P waste. Examples include, but are not limited to, condensate Tanks, crude oil Tanks, produced water Tanks, and gun barrels. Exclusions include Containers and process vessels such as separators, heater treaters, free water knockouts, and slug catchers.

UNDESIREABLE PLANT SPECIES are those species that possess unwanted or harmful characteristics. Undesirable plant species include but are not limited to, Noxious Weeds; non-native invasive species that replace or inhibit the establishment of native vegetation; native or non-native species that create monocultures or are overly dominant; species that by their presence reduce species diversity in vegetation communities; species that reduce or hinder agricultural productivity; species that exacerbate wind or water erosion; and species that increase fire risk.

SAFETY AND FACILITY OPERATIONS REGULATIONS

601. INTRODUCTION

The Commission's Rules in this section 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, Regional Administrator, Colorado Region VIII, 1244 Speer Blvd, Suite 551, Denver, CO 80204, 720-264-65550, or by visiting 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. Operators will ensure that all persons on an Oil and Gas Location or at an Oil and Gas Facility, including contractors and subcontractors, 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, for the protection of public health, safety, and welfare, the environment and wildlife resources, and to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

d. Operators will establish and maintain a written process safety management program for all Oil and Gas Operations. The process safety management program will include at a minimum:

(1) Management of Change program;

(2) Operational practices and procedure program; and a

(3) 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 an emergency that requires operations to cease due to an imminent threat to public health, safety, welfare, the environment, or wildlife resources, the Director may order a safety shut-in of an Oil and Gas Location until the emergency is resolved. An emergency shut-in that is ordered to last more than 72-hours will be brought before the Commission for hearing in accordance with Rule 528.

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

(1) Any accidental fire, explosion, or detonation, or uncontrolled release of pressure, 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 unsafe condition;

(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, in the version of 29 C.F.R. § 1904.39 in existence as of the date of this regulation and no later amendments. 29 C.F.R. § 1904.39 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. Additionally, 29 C.F.R. § 1904.39 may be found at https://www.osha.gov;

(3) A spill or release of hazardous chemicals, or a Grade 1 Gas Leak; and

(4) Any accident or natural event 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 Locations.

h. Initial notification from the Operator of a reportable safety event described in g.(1)-(4) above, will occur as soon as practicable, but no more than 6 hours after the safety event. An Accident Report, Form 22, 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 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 COGCC staff are on-site, the Operator will respond to and be present at the Location with first responders or COGCC staff.

j. All existing Oil and Gas Locations and all proposed Oil and Gas Locations will have an emergency response plan in place that has been coordinated with the local emergency response agencies.

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.

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. Self-contained physically secured sanitary facilities will be provided during drilling operations and at any other similarly staffed Oil and Gas Location or Oil and Gas Facility.

603. OPERATIONAL AND SAFETY REQUIREMENTS

a. **Blowout prevention equipment ("BOPE"). [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]** 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 Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate (Form 2), 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 psi/ft. For statewide BOPE specification, inspection, operation and testing requirements, see Rule 603.a.

(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 following the month in which such notice was given. The matter will be approved or heard by the Commission in accordance with 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 in accordance with the 500 Series Rules.

(2) Pursuant to Rule 603.a.(1), the Director may condition approval of any application for permit to drill 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 blowout prevention 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 both low-pressure air and high-pressure fluid.

(3) All Well servicing operations will be conducted in accordance with API Recommended Practice 54 (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 the API Recommended Practice 54 applies to this Rule later amendments do not apply. All material incorporated by reference in this rule 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, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070.

(4) An Operator will: **[This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]**

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 blowout preventer systems and/or diverter systems for Wells drilled with air, nitrogen, or foam.

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

(9) When required, blowout prevention equipment shall be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018). Only the 5th Edition of the API Standard 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, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070.

(10) Drilling after setting the surface casing will not proceed until blowout prevention equipment 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: "Blowout Prevention Equipment Systems for Drilling Wells," 5th Edition (December 2018), 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 blowout prevention equipment being tested, then there will be no unexplainable pressure loss at the end of the test.

(11) While in service, blowout prevention equipment 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 blowout prevention equipment, 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) Blowout prevention equipment 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 in accordance with 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 a FIT does not demonstrate the requirements as stated by 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 either a Mineral Management certification, or have completed a Director-approved blowout prevention training.

ii. All rig employees will have adequate understanding of and be able to operate the blowout prevention equipment system. New employees will be trained in the operation of blowout prevention 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 blowout prevention equipment 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.

(20) Each Operator will have a functioning emergency response plan that provides for the effective management of emergency situations that arise from oil and gas operations.

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 public health, safety, and welfare, the environment and wildlife resources, and to protect against adverse environmental impacts on any air, water soil, or biological resource resulting from Oil and Gas Operations.

e. **Development from existing Well pads.** Where possible, Operators will develop multiple reservoirs by drilling from existing Well sites or by multiple completions or commingling in existing wellbores (see Rule 404).

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 in accordance with National Fire Protection Association (NFPA) Code 30 (“Flammable and Combustible Liquids Code 2008 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 2008 version of NFPA Code 30 applies to this rule. This Rule does not include later amendments to, or editions of the NFPA Code 30. NFPA Code 30 may be examined at any state publication depository library. Upon request, the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203, and is available from the National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts, 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.

n. **Identification of plugged and abandoned Wells.** The Operator will identify the location of the wellbore with a permanent monument as specified in Rule 434.a.(6).

o. **Secondary Containment.** Secondary containment devices will be constructed around 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 attached to secondary containment and any equipment penetrating the liner with 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, 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 (January 2014) and the current national electrical code as adopted by the State of Colorado. Only the 3rd edition incorporated by reference within this Rule applies; later amendments do not apply. The material incorporated by reference in this Rule 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, these materials may be examined at any state publications depository library and are available from API at 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.

604. SETBACKS.

a. Well Location Requirements.

(1) At the time of initial drilling, a Well will be located not less than 200 feet from buildings, public roads, above ground utility lines, or railroads.

(2) 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). An exception request letter stating the reasons for the exception and a signed waiver(s) from the offset Surface Owner(s) will be submitted with the Form 2. Such waiver will be written and filed in the county clerk and recorder's office and with the Commission.

b. School Facility and Child Care Centers

(1) No Working Pad Surface will be located 2,000 feet or less from a School Facility or Child Care Center, unless the relevant School Governing Body agrees in writing to the location of the proposed Working Pad Surface.

(2) If the relevant School Governing Body does not agree in writing that the Working Pad Surface can be 2,000 feet or less from a School Facility or Child Care Center, the

Operator may seek Commission approval of the proposed Working Pad Surface Location in its Oil and Gas Development Plan.

(3) 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.

(4) Any hearing required under Rules 604.b. or 604.c. will be held at a location reasonably proximate to the lands affected by the Plan.

c. **Building Units.** No Working Pad Surface will be located less than 1,500 feet from 10 or more Building Units or 1 High Occupancy Building Unit, unless the Commission finds, after a hearing pursuant to Rule 510, that the location can be approved because the Commission has developed conditions of approval that protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

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) The Commission's assigned Oil and Gas Location identification number (ID #), and

(3) The Operator's telephone number where it may be reached at all times.

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 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 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 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 Locations, 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 in 605.d.(2) may be placed on one sign with dimensions as described in 605.d.(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 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 numbers 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.

f. Centralized E&P Waste Management Facility signage. 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:

(1) A phone number at which the Operator can be reached at all times;

(2) A phone number for local emergency services (911 where available);

(3) The public road used to access the facility; and

(4) The legal location, including quarter/quarter section, of the facility.

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 Commission's approval of a change of Operator, the new 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. National Fire Protection Association (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) Surface Owners may 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 Locations 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 exclude wildlife.

607. EQUIPMENT ANCHORING REQUIREMENTS.

All equipment at an Oil and Gas Location in a Geological 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.a.(2)B.

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 within this Rule will apply to this Rule; later amendments do not apply. The material incorporated by reference in this Rule 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, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070 and from Underwriters Laboratories, Inc. at 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,” 12th Edition (March 2013), including Errata 1 (2013), Errata 2 (2014), Addendum 1 (2014), Addendum 2 (2016), and Addendum 3 (2018);

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 No. 12F, “Shop Welded Tanks for Storage of Production Liquids,” 13th Edition (January 2019); or

F. API 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 it is built. Where the property line is a public way, the Tanks will be 2/3 of the diameter from the nearest side of the public 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 National Fire Protection Association (NFPA) Code 30, 2018 Edition unless otherwise specified. Only the 2018 version of NFPA Code 30 applies to this Rule. This Rule does not include later amendments to, or editions of the NFPA Cod 30. NFPA Code 30 may be examined at any state publication depository library. Upon request, the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203, and is available from the National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts, 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 fired vessel or heater-treater. No ancillary equipment which 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 Std 2000, "Venting Atmospheric and Low Pressure Storage Tanks", seventh edition, March 2014. Only the 7th Edition of the API standard applies to this Rule; later amendments do not apply. The API standard 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, these materials may be examined at any state publication depository library.

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 fired vessels in accord with API RP 12R-1, 5th Edition (August 1997, reaffirmed April 2, 2008). Only the 5th Edition of the API standard applies to this Rule; later amendments do not apply. The API standard 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, these materials may be examined at any state publication depository library.

(11) During hot oil treatments on Tanks containing 35 degree 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 in accordance with Rule 605.f.

(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 in accordance with Rule 906.

b. Fired Vessel, Heater-Treater, 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, fired vessels and heater treaters will be a minimum of 200 feet from buildings or well defined normally occupied outside areas.

(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 so as 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.

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 or well defined normally occupied outside area(s), 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 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, lighting and stray current requirements.** All equipment will be designed and operated in a manner to prevent accumulation of static charge in accordance with API RP 545, “Recommended Practice for Lightning Protection of Aboveground Storage Tanks for Flammable or Combustible Liquids,” 1st Edition, October 2009 and API RP 2003, “Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents,” 8th Edition, September 2015. Only the 1st Edition of API RP 545 and the 8th Edition API RP 2003 apply to this Rule and later amendments do not apply. All material incorporated by reference in this rule 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, these materials may be examined at any state publications depository library and are available from API at 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 manufactured 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 either the tank battery secondary containment liner.

(3) Operators will test buried or partially buried Tanks, vessels, or structures for leaks at least annually. Operators will maintain records documenting tests conducted pursuant to 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 and 913.

g. **Fluid Handling Equipment.** Any piece of fluid handling equipment that is not a Tank, 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 containment 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 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 an 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.

b. **Tank and Process Vessel Inspections.**

(1) All steel aboveground storage tanks (ASTs) will be inspected at least annually, and maintained in accordance with Steel Tank Institute (STI) SP001, "Standard for the Inspection of Aboveground Storage Tanks", January 2018 or API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction", Fifth Edition, whichever is applicable. Only the January 2018 Edition of SP001and the Fifth Edition of API Standard 653 applies to this Rule; later amendments do not apply. SP001, January 2018 Edition, and API Standard 653 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, these materials may be examined at any state publications depository library. SP001, January 2018 Edition is available from SPI at 944 Donata Court, Lake Zurich, IL 60047. API Standard 653 is available from API at 1220 L Street, NW Washington, DC 20005-4070.

(2) Operators will inspect all pressure vessels at least annually, pursuant to API Standard 510 "Pressure Vessel Inspector," 10th Edition. Only the 10th Edition 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, Colorado 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.

(3) Annual inspections required by Rule 609.b.(1)-(2) will be performed within 12 months of the effective date of this Rule 609. and annually thereafter.

c. **Audio Visual Olfactory Inspections.**

(1) Operators will conduct monthly Audio, Visual, Olfactory (AVO) inspections of all Oil and Gas Facilities.

(2) Upon the Director's request, the Operator will submit to the Director documentation of the results of all Tank system AVO inspections required by the Colorado Department of Public Health and Environment.

d. **Periodic Inspections.**

(1) External and internal inspections, and leak testing of ASTs, will be performed and documented according to API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction."

(2) These inspections will be performed by inspectors meeting the qualifications required by the standard being followed.

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). The Division of Oil and Public Safety's regulations are listed in 7 C.C.R. § 1101-15. The Division of Oil and Public Safety's regulations are standard 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, these materials may be examined at any state publication depository library. They are also available on the Division of Oil and Public Safety's website, https://www.colorado.gov/pacific/ops/RegulationsStatutes, or at the Division's office, 633 17th St., Suite 500, Denver, CO 80202.

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. Liquefied petroleum gas (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 58, "Standards for the Storage and Handling of Liquid Petroleum Gases".

f. Smoking will be 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," Third Edition, December 2012, as modified by the January 2014 errata, will be permitted on an Oil and Gas Locations or near Oil and Gas Facilities. The safety features of these heaters will not be altered. API RP 500 (3rd edition 2012) and the January 2014 errata 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, these materials may be examined at any state publications depository library and are available from API at 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, Tanks and separator. 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. 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 (January 2014) and the current national electrical code as adopted by the State of Colorado. Only the 3rd edition incorporated by reference within this rule will apply 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, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 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° F. For limited special purposes, a lower flash point cleaner may be used when it is specifically required and should be handled with extreme care.

m. Firefighting equipment will not be tampered with and will not be removed for other than 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 the "Standards for Portable Fire Extinguishers" (2018). NFPA 10: "Standard for Portable Fire Extinguishers," (2018 edition). Only the 2018 Edition of NFPA 10 applies to this Rule; later amendments do not apply. NFPA 10 (2018 edition) 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, these materials may be examined at any state publications depository library and are available from NFPA at 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, 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 (H_2S) gas. If releases or hazardous accumulations of H_2S cannot be avoided, or during upset conditions or malfunctions, Operators will employ mitigation measures to reduce potential harms to safety.

(2) **Scope.** To protect 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 H_2S.

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, H_2S 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 Outdoor Activity Area.

(1) Radius of exposure will be calculated in accordance with 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. Onshore Order 6 (1991) 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, these materials may be examined at any state publications depository library and are available from the U.S. Bureau of Land Management at 2850 Youngfield St., Lakewood, CO 80215.

(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 H_2S 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 of greater than 1 ppm H_2S to the Director and Local Governmental Designee, if applicable. If the Operator ever detects H_2S 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 Outdoor 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.

(3) The Director determines that a public protection plan is necessary to protect public health, safety, welfare, the environment, or wildlife resources, or to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

d. H_2S Drilling Plan.

(1) When proposing to drill a Well in areas where H_2S gas can reasonably be expected to be encountered, Operators will submit a H_2S drilling operations plan with their Form 2, Application-for-Permit-to-Drill.

(2) Operators will prepare the H_2S drilling operations plan in accordance with 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. Onshore Order 6 (1991) 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, these materials may be examined at any state publications depository library and are available from the U.S. Bureau of Land Management at 2850 Youngfield St., Lakewood, CO 80215.

e. Designated H_2S Locations. If an Operator ever measures H_2S gas stream concentrations of 100 ppm or greater at a Well, the Well is a designated H_2S location. All designated H_2S locations will be designed and operated in accordance with BLM Onshore Order No. 6. Only the 1991 version of Onshore Order 6 applies to this Rule; later amendments do not apply. Onshore Order 6 (1991) 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, these materials may be examined at any state publications depository library and are available from the U.S. Bureau of Land Management at 2850 Youngfield St., Lakewood, CO 80215. Designated H_2S locations will have:

(1) Signs indicating the presence of H_2S not less than 200 feet or more than 500 feet from the entrance of the location;

(2) H_2S monitoring with audible and visible alarms at 10 ppm of H_2S;

(3) At least one wind indicator; and

(4) Adequate fencing.

f. Operations in Designated H_2S Locations.

(1) In a designated H_2S location, Operators will employ a secondary means of immediate well control at all Wells, through the 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 H_2S 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 H_2S, or 10 ppm H_2S 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 H_2S concentrations greater than 100 ppm, will:

A. Use equipment that can withstand the effects and stress of H_2S;

B. Be conducted in accordance with ANSI/NACE Standard MR0175/ISO 15156-2015-SG "Petroleum and natural gas industries – Materials for use in H_2S-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. ANSI/NACE Standard MR0175/ISO 15156-2015-SG (2015) 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, these materials may be examined at any state publications depository library and is available from NACE International 15835 Park Ten Pl, Houston, Texas 77084; and

C. If applicable, use adequate protection by chemical inhibition or such other methods that control or limit H_2S's corrosive effects.

(4) Operators in designated H_2S locations will analyze their gas stream for H_2S at least monthly. If the H_2S concentration increases by greater than 25%, the Operator will recalculate the radius of exposure and notify the Director and the Local Governmental Designee, if applicable.

g. Operator Reports of H_2S. Operators will report any gas stream laboratory analysis indicating concentrations of H_2S gas greater than 100 ppm to the Director and the Local Governmental Designee, if applicable, within 48 hours.

h. Operators may only intentionally release H2S gas with prior Director approval of a Form 4, Sundry Notice. The Form 4 will include a proposed air monitoring plan for H_2S. If combustion or flaring is proposed, the air monitoring plan will include a SO_2 by-product detection plan.

i. All H_2S monitoring, mitigation and safety equipment will be maintained and functioning in good working order at all times.

j. Temporary Abandonment of a H_2S Well.

(1) Operators will obtain the Director's approval prior to temporarily abandoning a Well with potential concentrations of greater than 100 ppm H_2S in its gas stream.

(2) Operators will install a cast iron bridge plug and maintain H_2S monitoring and telemetry equipment when temporarily abandoning a Well with potential concentrations of greater than 100 ppm H_2S 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 in accordance with Rule 912 and will submit the COGCC Spill/Release Report, Form 19, document number on a Flowline Report, Form 44 for the Grade 1 Gas Leak.

614. COALBED METHANE WELLS [This section includes rule text currently proposed, but not yet adopted by the Commission in its Wellbore Integrity rulemaking Docket No. 191200754.]

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 in accordance with 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. 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 Bottom Hole Pressure, Form 13, and submitted with the Completed Interval Report, Form 5A, 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.

c. CBM Monitoring. If a conventional gas well or P&A well exists within one-quarter 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 one-half mile radius of the conventional gas well or the P&A well shall be sampled ("Water Quality Testing Wells") in accordance with Rule 615.c.-f.

(1) If possible, the water wells selected should be on opposite sides of the conventional gas well or the P&A well not exceeding a one-half mile radius. If water wells on opposite sides of the conventional gas well or the P&A well cannot be identified, then the 2 closest wells within a one-half mile radius of the conventional gas well or the P&A well will be sampled.

(2) If 2 or more conventional wells or P&A wells are located within one quarter mile of the proposed CBM well, then the conventional well or the P&A well closest to a proposed CBM well shall be used for selecting water wells for sampling.

(3) If there are no conventional gas wells or P&A wells located within a one-quarter mile radius of the proposed CBM well this Rule 614.c. will not apply.

d. **Bradenhead Testing.** An Operator of a coalbed methane well will comply with Rule 419, except as modified by this Rule. 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 (hereinafter, Oil and Gas Wells), Multi-Well Sites, and Dedicated Injection Wells for which a Form 2, Application for Permit-to-Drill, or Form 4, Notice to Recomplete, is submitted or pending on or after September 15, 2020. Oil Wells, Gas Wells, Multi-Well Sites, and Dedicated Injection Wells operating under a Form 2 approved prior to September 15, 2020, 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 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 Rules, including but not limited to the Oil and Gas Location Assessment process, and other processes in place under 900-series E&P Waste Management Rules (Form 15, Form 27, Form 28).

(3) An Operator may elect 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.

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 Dedicated Injection 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 Dedicated Injection Well, the Operator will select the four sampling locations based on the following criteria:

(1) **Proximity.** Available Water Sources closest to the proposed Oil or Gas Well, a Multi-Well Site, or Dedicated Injection 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 Well, Gas Well, Multi-Well Site, or Dedicated Injection 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 by filing a Form 4, Sundry Notice, 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 Dedicated Injection Well;

(2) The only Available Water Sources are determined to be unsuitable pursuant to Rule 615.b.(5), above. 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 under 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 Sundry Notice within 10 business days of receipt, the requested exception from the requirements of this Rule 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 Dedicated Injection 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 Dedicated Injection Well, or the last Well on a Multi-Well Site. Additional subsequent samples will be collected every five 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 Well or 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 subpart d.

(3) Previously sampled Water Sources. In lieu of conducting the initial sampling required pursuant to subsection d.(1), or the second subsequent sampling event required pursuant to subsection 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 subsection d.(1), or any subsequent sampling event required pursuant to subsection 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 subparts e.(1) and (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.

e. Sampling procedures and analysis.

(1) Sampling and analysis will be conducted in conformance with an accepted industry standard as described in Rule 913.b.(2). A model Sampling and Analysis Plan ("COGCC Model SAP") will be posted on the COGCC 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 subsection 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 and subsequent will include:

A. pH;

B. specific conductance;

C. total dissolved solids (TDS);

D. dissolved gases (methane, ethane, propane);

E. alkalinity (total, bicarbonate and carbonate as $CaCO_3$);

F. major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrite as N, phosphorus);

G. major cations (calcium, iron, magnesium, manganese, potassium, sodium);

H. other elements (barium, boron, selenium and strontium);

I. presence of bacteria (iron related, sulfate reducing, 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).

(3) Field observations such as odor, water color, sediment, bubbles, and effervescence as well as the presence or absence of hydrogen sulfide gas will be documented. The location of the sampled Water Sources will be surveyed in accordance with Rule 215.

(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. ethane;

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 ofC1;

iii. delta 13C of C2;

iv. delta 13C ofC3;

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 CO_2.

C. The Operator will notify the Director by Form 42 and 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, and provide a copy of the Form 42 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 available publicly 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 Governmental Designee from the jurisdiction in which the groundwater samples were collected, in the same electronic data deliverable format.