E&P WASTE MANAGEMENT

901. INTRODUCTION

a. **General.** The rules and regulations of this series establish the permitting, construction, operating and closure requirements for pits, methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. The 900 Series rules are applicable only to E&P waste, as defined in § 34-60-103(4.5), C.R.S., or other solid waste where the Colorado Department Of Public Health And Environment has allowed remediation and oversight by the Commission.

b. **COGCC reporting forms.** The reporting required by the rules and regulations of this series shall be made on forms provided by the Director. Alternate forms may be used where equivalent information is supplied and the format has been approved by the Director.

c. **Additional requirements.** Whenever the Director has reasonable cause to believe that an operator, in the conduct of any oil or gas operation, is performing any act or practice which threatens to cause or causes a violation of Table 910-1 and with consideration of water quality standards or classifications established by the Water Quality Control Commission (“WQCC”) for waters of the state, the Director may impose additional requirements, including but not limited to, sensitive area determination, sampling and analysis, remediation, monitoring, permitting and the establishment of points of compliance. Any action taken pursuant to this Rule shall comply with the provisions of Rules 324A. through D. and the 500 Series rules.

d. **Alternative compliance methods.** Operators may propose for prior approval by the Director alternative methods for determining the extent of contamination, sampling and analysis, or alternative cleanup goals using points of compliance.

e. **Sensitive area determination.** When the operator or Director has data that indicate an impact or threat of impact to ground water or surface water, the Director may require the operator to make a sensitive area determination and that determination shall be subject to the Director’s approval. The sensitive area determination shall be made using appropriate geologic and hydrogeologic data to evaluate the potential for impact to ground water and surface water, such as soil borings, monitoring wells, or percolation tests that demonstrate that seepage will not reach underlying ground water or waters of the State and impact current or future uses of these waters. Operators shall submit data evaluated and analysis used in the determination to the Director.

f. **Sensitive area operations.** Operations in sensitive areas shall incorporate adequate measures and controls to prevent significant adverse environmental impacts and ensure compliance with the concentration levels in Table 910-1, with consideration to WQCC standards and classifications.

902. PITS - GENERAL AND SPECIAL RULES

a. Pits used for exploration and production of oil and gas shall be constructed and operated to protect public health, safety, and welfare and the environment, including soil, waters of the state, and wildlife, from significant adverse environmental, public health, or welfare impacts from E&P waste, except as permitted by applicable laws and regulations.

b. Pits shall be constructed, monitored, and operated to provide for a minimum of two (2) feet of freeboard at all times between the top of the pit wall at its point of lowest elevation and the fluid level of the pit. A method of monitoring and maintaining freeboard shall be employed.

name, a description of the location, type, capacity and use of pit, engineering design, installation features and water quality data, if available, was required for the following:

A. Lined production pits and lined special purpose pits constructed after July 1, 1995.

B. Unlined production pits constructed prior to July 1, 1995 which are lined in accordance with Rule 905. by December 30, 1997.

(2) An Application For Permit For Unlined Pit, Form 15 was required for the following:

A. Unlined production pits and special purpose pits in sensitive areas constructed prior to July 1, 1995, and not closed by December 30, 1997.

B. Unlined production pits outside sensitive areas constructed after July 1, 1995 and not closed by December 30, 1997.

(3) An Application For Permit For Unlined Pit, Form 15 and a variance under Rule 904.e.(1). (repealed, now Rule 502.b.) was required for unlined production pits and unlined special purpose pits in sensitive areas constructed after July 1, 1995.

(4) A Sundry Notice, Form 4 was required for unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation constructed prior to December 30, 1997.

e. The Director may have established points of compliance for unlined production pits and special purpose pits and for lined production pits in sensitive areas constructed after July 1, 1995.

f. **Closure requirements.**

(1) Operators of production or special purpose pits existing on July 1, 1995 which were closed before December 30, 1997, were required to submit a Sundry Notice, Form 4, within thirty (30) days of December 30, 1997. The Sundry Notice, Form 4 shall include a copy of the existing pit permit, if a permit was obtained, and a description of the closure process.

(2) Pits closed prior to December 30, 1997 were required to be reclaimed in accordance with the 1000 Series rules. Pits closed after December 30, 1997 shall be closed in accordance with the 900 Series rules and reclaimed in accordance with the 1000 Series rules.

(3) Operators of steel, fiberglass, concrete or other similar produced water vessels buried or partially buried and located in sensitive areas were required to repair or replace vessels and tanks found to be leaking. Operators shall repair or replace vessels and tanks found to be leaking. Operators shall submit to the Director a Sundry Notice, Form 4, describing the integrity testing results and action taken within thirty (30) days of December 30, 1997.

(4) Closure of pits and steel, fiberglass, concrete or other similar produced water vessels, and associated remediation operations conducted prior to December 30, 1997 are not subject to Rules 905., 906., 907., 909. and 910.

912. VENTING OR FLARING NATURAL GAS

a. The unnecessary or excessive venting or flaring of natural gas produced from a well is prohibited.

b. Except for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test, gas from a well shall be flared or vented only after notice has been given and approval obtained from the Director on a Sundry Notice, Form 4, stating the estimated volume and content of the gas. The notice shall indicate whether the gas contains more than one (1) ppm of hydrogen sulfide. If necessary to protect the public health, safety or welfare, the Director may require the flaring of gas.

c. Gas flared, vented or used on the lease shall be estimated based on a gas-oil ratio test or other equivalent test approved by the Director, and reported on Operator's Monthly Report of Operations, Form 7.

d. Flared gas that is subject to Sundry Notice, Form 4, shall be directed to a controlled flare in accordance with Rule 903.b.(2) or other combustion device operated as efficiently as possible to provide maximum reduction of air contaminants where practicable and without endangering the safety of the well site personnel and the public.

e. Operators shall notify the local emergency dispatch or the local governmental designee of any natural gas flaring. Notice shall be given prior to flaring when flaring can be reasonably anticipated, or as soon as possible, but in no event more than two (2) hours after the flaring occurs.

Table 910-1
CONCENTRATION LEVELS[1]

Contaminant of Concern	Concentrations
Organic Compounds in Soil	
TPH (total volatile and extractable petroleum hydrocarbons)	500 mg/kg
Benzene	0.17 mg/kg[2]
Toluene	85 mg/kg[2]
Ethylbenzene	100 mg/kg[2]
Xylenes (total)	175 mg/kg[2]
Acenaphthene	1,000 mg/kg[2]
Anthracene	1,000 mg/kg[2]
Benz(a)anthracene	0.22 mg/kg[2]
Benzo(b)fluoranthene	0.22 mg/kg[2]
Benzo(k)fluoranthene	2.2 mg/kg[2]
Benzo(a)pyrene	0.022 mg/kg[2]
Chrysene	22 mg/kg[2]
Dibenzo(a,h)anthracene	0.022 mg/kg[2]
Fluoranthene	1,000 mg/kg[2]
Fluorene	1,000 mg/kg[2]
Indeno(1,2,3,c,d)pyrene	0.22 mg/kg[2]
Naphthalene	23 mg/kg[2]
Pyrene	1,000 mg/kg[2]
Organic Compounds in Ground Water	
Benzene	5 μg/l[3]
Toluene	560 to 1,000 μg/l[3]
Ethylbenzene	700 μg/l[3]
Xylenes (Total)	1,400 to 10,000 μg/l[3,4]
Inorganics in Soils	
Electrical Conductivity (EC)	<4 mmhos/cm or 2x background

DEFINITIONS
100 SERIES

CENTRALIZED E&P WASTE MANAGEMENT FACILITY means a facility, other than a commercial disposal facility regulated by CDPHE, that (1) is either used exclusively by one owner or Operator or used by more than one Operator under an operating agreement; and (2) is operated for a period greater than three years; and (3) receives for collection, treatment, temporary storage, and/or disposal produced water, drilling fluids, completion fluids, and any other exempt E&P Wastes that are generated from two or more production units or areas or from a set of commonly owned or operated leases. This definition includes oil-field naturally occurring radioactive materials ("NORM") related storage, decontamination, treatment, or disposal. This definition excludes a Multi-Well Pit that meets the standards of Rules 909.g.(2)–(3).

COMMENCEMENT OF PRODUCTION OPERATIONS means the date that product consistently flows to a sales line, Gathering Line, or Tank from a Well.

COMPLETED WELL means a Well in which oil or gas is produced through wellhead equipment from the producing interval(s) after the production string has been installed.

CUTTINGS TRENCH means a depression used specifically for the onsite storage and disposal of dried cuttings generated from drilling a Well.

FLARING means the combustion of natural gas during upstream Oil and Gas Operations, excluding gas that is intentionally used for onsite processes.

FLOWBACK means the process of allowing Fluids and entrained solids to flow from a Well following Stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the Well into production. The term Flowback also means the Fluids and entrained solids that emerge from a Well during the Flowback process.

INVESTIGATION-DERIVED WASTE means those materials generated during site investigation and Remediation activities, including but not limited to personal protective equipment, soil cuttings, drilling mud, purged Groundwater, decontamination fluids, and disposable or consumable equipment and supplies.

LAND APPLICATION means the disposal method by which treated E&P Waste is spread upon and mixed into soils.

LAND TREATMENT means the method by which E&P Waste is treated *ex situ* at the land surface to result in a reduction of hydrocarbon concentration by biodegradation and other natural attenuation processes. Land Treatment may be enhanced by tilling, disking, aerating, composting, or adding nutrients or microbes.

MULTI-WELL PITS means Pits used for treatment, storage, recycling, reuse, or disposal of E&P Wastes generated from more than one Well.

OILY WASTE means those materials containing unrefined petroleum hydrocarbons in concentrations in excess of the concentration levels in Table 915-1. Oily waste may include crude oil, condensate, or other materials such as soil, frac sand, drilling fluids, cuttings, and Pit sludge that contain hydrocarbons.

POLLUTION means anthropogenic contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resources that is not authorized or allowed by the Commission's Rules or applicable regulations promulgated by another federal, state, or Local Government agency.

PRODUCTIVITY TEST means a test for determination of a reservoir's ability to produce economic quantities of oil or gas.

PRODUCTION EVALUATION means an evaluation of production potential for determination of requirements for infrastructure capacity and equipment sizing.

REMEDIATION means the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with the concentration levels in Table 915-1 and other applicable Groundwater standards and classifications.

UPSET CONDITION means a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction.

VENTING means allowing natural gas to escape into the atmosphere, but does not include:

a. The emission of gas from devices, such as pneumatic devices and pneumatic pumps, that are designed to emit as part of normal operations if such emissions are not prohibited by AQCC Regulation No. 7, as incorporated by reference in Rule 901.b;

b. Unintentional leaks that are not the result of inadequate equipment design; and

c. Natural gas escaping from, or downstream of, a Tank unless: 1) there is no separation occurring at equipment upstream of the Tank; 2) the separation equipment is not sufficiently sized to capture the entrained gas; or 3) the natural gas is sent to the Tank during circumstances when the gas cannot be sent to the Gathering Line or the combustion equipment used to Flare the gas is not operating.

ENVIRONMENTAL IMPACT PREVENTION
900 SERIES

901. GENERAL STANDARDS

a. Addressing Impacts and Potential Impacts to Public Health, Safety, Welfare, the Environment, and Wildlife Resources. Whenever the Director has reasonable cause to determine that an Operator, in the conduct of any Oil and Gas Operations, is impacting or threatening to impact public health, safety, welfare, the environment, or wildlife resources, the Director may require the Operator to take action to avoid, minimize, or mitigate the potential impacts to public health, safety, welfare, the environment, or wildlife resources, including but not limited to:

(1) Suspending operations or initiating immediate mitigation measures until the cause of the threat or potential threat to public health, safety, welfare, the environment, or wildlife resources is identified and the threat or potential threat to public health, safety, welfare, the environment, or wildlife resources is corrected.

(2) Submitting a Form 27, Site Investigation and Remediation Workplan, for site characterization, Remediation, monitoring, permitting, and the establishment of points of compliance.

(3) If the Director requires an Operator to take action pursuant to this Rule 901.a, 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 this Rule 901.a until the Commission makes a decision on the appeal. The Commission may uphold the Director's decision if the Commission determines the Director had reasonable cause to determine that an Operator's actions impacted or threatened to impact public health, safety, welfare, the environmental, or wildlife resources, and that the action required by the Director was necessary and reasonable to avoid, minimize, or mitigate those impacts or threatened impacts.

b. Incorporation by Reference. Pursuant to § 24-4-103(12.5), C.R.S., the Commission incorporates by reference into these 900 Series Rules the following codes, standards, guidelines, and rules of other federal agencies, state agencies, and nationally recognized organizations and associations.

(1) Where Materials May Be Found.

A. Copies of all materials incorporated by reference 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.

B. Copies of all materials incorporated by reference are also available at the office or website of the agency or organization that issued the code, standard, guideline, or rule, as specified below.

C. Copies of any materials that are not available to the public on the internet for no cost may be examined at any state publications depository library.

(2) Current Version. Only the version of the code, standard, guideline, or rule in effect as of January 15, 2020, and no later amendments or editions of the code, standard, guideline, or rule are incorporated by reference, unless otherwise specified below.

(3) Materials Incorporated.

A. Colorado Department of Public Health and Environment, Water Quality Control Commission ("WQCC"), Regulation Number 41, The Basic Standards for Ground Water, 5 C.C.R. § 1002-41, *et seq.* (hereinafter "WQCC Regulation 41"). Only the version of WQCC Regulation 41 in effect as of January 15, 2021 applies; later amendments do not apply. WQCC Regulation 41 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at https://cdphe.colorado.gov/water-quality-control-commission-regulations.

B. Colorado Department of Public Health and Environment, Solid and Hazardous Waste Commission ("SHWC"), Regulations Pertaining to Solid Waste, 6 C.C.R. § 1007-2*, et seq.* (hereinafter "SHWC Solid Waste Regulations"). Only the version of the SHWC Solid Waste Regulations in effect as of January 15, 2021 applies; later amendments do not apply. The SHWC Solid Waste Regulations may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available online at https://cdphe.colorado.gov/solid-waste-regulations.

C. SHWC Regulations Pertaining to Hazardous Waste, 6 C.C.R. § 1007-3, *et seq.* (hereinafter "SHWC Hazardous Waste Regulations"). Only the version of the SHWC Hazardous Waste Regulations in effect as of January 15, 2021 applies; later amendments do not apply. The SHWC Hazardous Waste Regulations may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available online at https://cdphe.colorado.gov/hazardous-waste-regulations.

D. Colorado Department of Public Health and Environment, Air Quality Control Commission ("AQCC"), Regulation No. 7, Control of Ozone Via Ozone Precursors and Control of Hydrocarbons Via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides), 5 C.C.R. § 1001-9, *et seq.* (hereinafter "AQCC Regulation No. 7"). Only the version of AQCC Regulation No. 7 in effect as of January 15, 2021 applies; later amendments do not apply. AQCC Regulation No. 7 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at https://cdphe.colorado.gov/aqcc-regulations.

E. Colorado State Board of Examiners of Water Well Construction and Pump Installation Contractors, Rules and Regulations for Water Well Construction, Pump Installation, Cistern Installation, and Monitoring and Observation Hole/Well Construction, 2 C.C.R. § 402-2, *et seq.* (hereinafter "State Engineer's Water Well Construction and Permitting Rules"). Only the version of the State Engineer's Water Well Construction Rules in effect as of January 15, 2021 applies; later amendments do not apply. The State Engineer's Water Well Construction and Permitting Rules may be examined at the Colorado Division of Water Resources, 1313 Sherman St., Suite 821, Denver, CO 80203, and are available online at https://dwr.colorado.gov/services/well-construction-inspection.

F. U.S. Environmental Protection Agency, Test Methods for Evaluating Solid Waste: Physical/Chemical Methods (May 2019 edition) (hereinafter, "EPA SW-846"). Only the May 2019, "Update VI" edition of EP SW-846 applies to this rule; later amendments do not apply. EPA SW-846 may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and is available online at https://www.epa.gov/hw-sw846/sw-846-compendium.

G. U.S. Environmental Protection Agency, 40 C.F.R. § 60.5375a, What GHG and VOC standards apply to well affected facilities? (2016) (hereinafter, "40 C.F.R. § 60.5375a"). Only the version of 40 C.F.R. § 60.5375a that became effective on August 2, 2016 applies to this rule; later amendments do not apply. 40 C.F.R. § 60.5375a may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and is available online at https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf.

H. U.S. Environmental Protection Agency, Regional Screening Levels for Chemical Contaminants at Super Fund Sites (Nov. 18, 2020) (hereinafter, "EPA's RSLs"). Only the November 2020 version of EPA's RSLs applies; later amendments do not apply. EPA's RSLs may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and are available online at https://www.epa.gov/risk/regional-screening-levels-rsls-generic-tables.

I. Western Coordinating Committee on Nutrient Management, Soil, Plant and Water Reference Methods for the Western Region (4th edition, 2013). Only the 4th edition (2013) of the Soil, Plant and Water Reference Methods for the Western Region applies to this rule; later amendments do not apply. Soil, Plant and Water Reference Methods for the Western Region may be examined at the Soil Science Society of America, 5585 Guilford Road, Madison, WI 53711, and is available online at https://www.naptprogram.org/files/napt/publications/method-papers/western-states-methods-manual-2013.pdf.

J. Rocky Mountain Low-Level Radioactive Waste Board, Rules (Dec. 3, 2010). Only the 2010 version of the Rocky Mountain Low-Level Radioactive Waste Board's Rules apply to this Rule; later amendments do not apply. The Rocky Mountain Low-Level Radioactive Waste Board's Rules may be examined at Rocky Mountain Low-Level Radioactive Waste Board, 999 18th St., Suite 2400 S, Denver, CO 80202, and are available online at http://www.rmllwb.us/documents/Rules_12-3-10.pdf.

902. POLLUTION

a. Operators will prevent Pollution.

b. Operators will prevent adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

c. Operators will prevent the unauthorized discharge or disposal of oil, condensate, gas, E&P Waste, Chemical substances, trash, discarded equipment, and other oil field waste.

d. No Operator, in the conduct of any Oil or Gas Operation, may violate numeric or narrative water quality standards or classifications established by the WQCC for Waters of the State, or any Point of Compliance established by the Director pursuant to Rule 914. The Director may require the Operator to establish one or more Points of Compliance for any event of Pollution, which will be complied with by all parties determined to be a Responsible Party for such Pollution.

e. No Operator, in the conduct of any Oil or Gas Operation, may violate any applicable air quality law, regulation, or permit as administered by the Air Quality Control Commission or any other local or federal agency with authority for regulating air quality associated with such activities.

f. No person may accept water produced from Oil and Gas Operations, or other oil field waste for disposal in a commercial disposal facility, without first obtaining a certificate of designation from the county in which such facility is located, in accordance with the regulations pertaining to Solid Waste Disposal sites and facilities as promulgated by CDPHE.

903. VENTING OR FLARING NATURAL GAS

Venting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, are prohibited.

a. Notice to Local Governments and Emergency Responders.

(1) **Prior Notice.** As soon as practicable prior to, but no later than two hours before, any planned Flaring of natural gas allowed pursuant to this Rule 903, Operators will provide verbal, written, or electronic notice to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(2) **Subsequent Notice.** In the event of Flaring due to an Upset Condition, Operators will provide verbal, or electronic notice as soon as possible, but no later than 12 hours, to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(3) **Waiver.** Relevant and Proximate Local Governments and local emergency response authorities may waive their right to notice under this Rule 903.a at any time, pursuant to Rule 302.f.(1).A.

(4) **Recordkeeping.** Operators will maintain records of notice provided pursuant to this Rule 903.a, and provide the records to the Director upon request.

b. Emissions During Drilling Operations.

(1) Operators will capture or combust gas downstream of the mud-gas separator using best drilling practices while maintaining safe operating conditions.

(2) If capturing or combusting gas would pose safety risks to onsite personnel, Operators may Vent and will provide verbal notification to the Director within 12 hours and submit a Form 4, Sundry Notice within 7 days. The Operator need not seek a formal variance pursuant to Rule 502. A Form 23, Well Control Report may also be required if the criteria in Rule 428.c are met. If Venting pursuant to this Rule 903.b.(2) exceeds 24 hours, the Operator will seek the Director's approval to continue Venting.

(3) Combustors will be located a minimum of 100 feet from the nearest surface hole location and enclosed.

c. Emissions During Completion Operations.

(1) **Reduced Emission Completions Practices.** Operators will adhere to reduced emission completion practices as specified in 40 C.F.R. § 60.5375a, as incorporated by reference in Rule 901.b, on all newly Completed and re-completed oil and gas Wells regardless of whether the Well is hydraulically fractured, unless otherwise specified in this Rule 903.c.

(2) **Flowback Vessels.** Operators will enclose all Flowback vessels and adhere to the AQCC Regulation No. 7 standards for emission reduction from pre-production Flowback vessels as specified in 5 C.C.R. § 1001-9:D.VI.D, as incorporated by reference in Rule 901.b.

(3) Operators may Flare gas during completion operations with specific written approval from the Director under any of the following circumstances:

A. The Operator obtains the Director's approval to Flare through an approved gas capture plan pursuant to Rule 903.e;

B. The Operator submits, and the Director approves, a Form 4 allowing the Operator to Flare gas that would otherwise not be permitted pursuant to Rule 903.c.

i. On the Form 4 the Operator will explain why Flaring is necessary to Complete the Well, and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

ii. On the Form 4 the Operator will estimate anticipated Flaring volume and duration.

iii. On the Form 4 the Operator will explain its plan to connect the facility to a Gathering Line or otherwise utilize the gas in the future.

iv. The Director may approve a Form 4 requesting permission to Flare during completion if the Director determines that the Flaring is necessary to Complete the Well and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources; or

C. The Operator may direct gas to an emission control device and combust the gas if necessary to ensure safety or during an Upset Condition for a period not to exceed 24 cumulative hours. If Flaring pursuant to this Rule 903.c.(3).C exceeds 24 hours, the Operator will seek the Director's approval to continue Flaring. Within 7 days of the Flaring event, the Operator will submit a Form 4 reporting the Upset Condition or safety issues that resulted in the Flaring event and include the estimated volume of gas Flared.

d. Emissions During Production.

(1) After the Commencement of Production Operations at an Oil and Gas Location, Venting or Flaring of natural gas produced from any Completed Well is prohibited except under the following circumstances:

A. Gas Flared or Vented during an Upset Condition is allowed for a period necessary to address the upset, not to exceed 24 cumulative hours. Operators will maintain records of the date, cause, estimated volume of gas Flared or Vented, and duration of each Upset Condition resulting in Flaring or Venting, and will make such records available to the Director upon request.

B. Gas Vented during and as part of active and required maintenance and repair activity, including pipeline pigging, as long as the Venting is not prohibited by AQCC Regulation No. 7, 5 C.C.R. § 1001-9, as incorporated by reference in Rule 901.b. Operators will use operational best practices to minimize Venting during maintenance and repair activity.

C. If approved by the Director on a Gas Capture Plan pursuant to Rule 903.e, gas Flared during a Production Evaluation or Productivity Test for a period not to exceed 60 days.

D. Gas Vented during a Bradenhead test pursuant to Rule 419.

E. Any event of Well liquids unloading, as long as the Well liquids unloading employs best management practices to minimize hydrocarbon emissions as required by the AQCC Regulation No. 7, 5 C.C.R. § 1001-9, as incorporated by reference in Rule 901.b. Operators will capture or Flare gas escaping into the air during liquids unloading if the escape of the gas poses a risk to public health, safety, or welfare due to the risk of a fire, explosion, or inhalation. Pursuant to Rule 405.s, all Well liquids unloading, including swabbing, will be reported to the Director. The Operator will submit a Form 42, Field Operations Notice – Notice of Well Liquids Unloading, no less than:

i. 48 hours prior to conducting Well liquids unloading; or

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

F. Flaring or Venting approved pursuant to Rule 903.d.(3) or on a Form 4 prior to January 15, 2021.

(2) For any instance of Venting or Flaring permitted pursuant to Rules 903.d.(1).A–E for a period that exceeds 8 consecutive or 24 cumulative hours, the Operator will submit a Form 4 reporting:

A. The estimated or measured volume and content of gas Vented or Flared;

B. Gas analysis of the gas Vented or Flared, including hydrogen sulfide;

C. Explanation, rationale, and cause for the Venting or Flaring event; and

D. A description of any operational best practices used to minimize Venting during maintenance and repair activity.

(3) At Wells that have Commenced Production Operations prior to January 15, 2021 and that are Venting or Flaring natural gas because they are not connected to a natural gas Gathering Line or putting the natural gas to beneficial use, the Operator may request permission from the Director to Flare or Vent by submitting a gas capture plan via a Form 4 no later than the date the Operator's previously approved Form 4 expires and in no case later than January 15, 2022. If an Operator loses access to a Gathering Line after January 15, 2021, the Operator will submit a gas capture plan via a Form 4 within 30 days of losing the Gathering Line access. The Operator may not Flare or Vent pursuant to this Rule 903.d.(3) unless and until the Director approves the Form 4. The Director may approve a one-time request to Flare or Vent for a period not to exceed 12 months, if the Director determines that Flaring or Venting is necessary to produce the Well, will minimize waste, and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. For any such Form 4 submitted prior to January 15, 2022, the Director will not approve the one-time request to Flare or Vent to any date after January 15, 2022. The gas capture plan on the Form 4 will describe:

A. The estimated volume and content of the gas to be Flared or Vented;

B. Gas analysis including hydrogen sulfide for the subject Well;

C. For requests based on lack of available infrastructure, the Operator will state why the Well cannot be connected to infrastructure;

D. When the Well(s) will be connected to infrastructure, why the Operator commenced production of the Well before infrastructure was available, and whether the mineral Owner will be compensated for the Vented or Flared gas; and

E. Options for using the gas instead of Flaring or Venting, including to generate electricity, gas processing to recover natural gas liquids, or other options for using the gas.

(4) Measurement and Reporting.

A. Operators will measure the volume of all gas Vented, Flared, or used at an Oil and Gas Location by direct measurement or by estimating the volume of gas Vented, Flared or used. The volume of gas Vented, Flared, or used will be reported on a per Well basis on the Form 7, Operator's Monthly Report of Operations.

B. Operators will notify all mineral Owners of the volume of oil and gas that is Vented, Flared, or used on-lease. Operators will maintain records of such notice and provide the records to the Director upon request.

(5) All Flared gas will be combusted in an enclosed device equipped with an auto-igniter or continuous pilot light and a design destruction efficiency of at least 98% for hydrocarbons.

(6) Pits.

A. Pits Constructed After January 15, 2021.

i. Operators will design, construct, and operate new Pits that are within 2,000 feet of an existing Building Unit or Designated Outside Activity Area to emit less than 2 tons per year ("tpy") volatile organic compounds ("VOCs").

ii. Operators will design, construct, and operate new Pits within Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson, Larimer, and Weld Counties to emit less than 2 tpy VOCs.

iii. Operators will design, construct, and operate new Pits in locations that do not meet the criteria of Rules 903.d.(6).A.i–ii to emit less than 5 tpy VOCs, unless:

aa. The Pit is used for recycling or reuse of produced water, subject to the approval of a reuse and recycling plan pursuant to Rule 905.a.(3);

bb. The Operator utilizes a centralized water distribution system to minimize trucks used to transport produced water; and

cc. The Director approves the Operator's plan to minimize emissions pursuant to Rule 903.d.(6).A.iv based on consultation with the Air Pollution Control Division.

iv. Operators will design, construct, and operate new Pits to utilize control technology to minimize emissions to the extent reasonably achievable based on best available practices.

B. Pits Constructed Prior to January 15, 2021. After January 15, 2023, all Pits constructed prior to January 15, 2021 will be operated to emit less than 5 tpy VOCs, unless:

i. The Pit is used for recycling or reuse of produced water and the Pit utilizes control technology to minimize emissions to the extent reasonably achievable, and the Operator submits and obtains the Director's approval of a reuse and recycling plan that meets the requirements of Rule 905.a.(3); or

ii. The Operator submits a Form 15, Earthen Pit Report/Permit pursuant to Rule 903.a.(6).C demonstrating that a greater allowable rate of emissions from the Pit is reasonable and necessary, and the Director approves the Form 15 based on consultation with the Air Pollution Control Division.

C. Operators will provide the basis for their determination of applicability under Rule 903.d.(6) to the Director on a Form 15 submitted concurrently with the initial produced water quality analysis required by Rule 909.j. The basis for determination of applicability will:

i. State the Pit's estimated annual emissions in tpy VOCs;

ii. Describe the method used to estimate emissions; and

iii. If the Operator seeks an exception pursuant to Rules 903.d.(6).B.i or ii, describe the basis for why the exception should be granted.

e. Gas Capture Plans.

(1) Gas Capture Plan Submission.

A. On a Form 2A, Oil and Gas Location Assessment the Operator will commit to connecting to a gathering system by the Commencement of Production Operations, or submit a gas capture plan as an attachment to their Form 2A, pursuant to Rule 304.c.(12).

B. Gas capture plans will demonstrate compliance with the requirements of Rules 903.b–d and include the following information:

i. A description and map of the location of the closest or contracted natural gas gathering system or point of sale.

ii. The name of the company operating the closest or contracted natural gas gathering system.

iii. The Operator's plan for connecting their facility to a natural gas gathering system or otherwise putting gas to beneficial use, including:

aa. Discussion of potential rights of way issues;

bb. Construction schedules;

cc. Date of availability of the gas Gathering Line;

dd. Whether the nearest or contracted gas gathering system has capacity to accept the anticipated gas to be produced at the location at the time of application; and

ee. Options for beneficial use of natural gas that are alternatives to Flaring during production operations prior to connection to gas Gathering Lines, including, but not limited to: onsite use, natural gas liquid processing, electrical power generation, gas to liquid, reinjection for enhanced oil recovery, or other options.

iv. For a Wildcat (Exploratory) Well or if the Operator anticipates conducting a Production Evaluation or Productivity Test, a description of the planned Production Evaluation or Productivity Test and any issues related to the Operator's ability to connect to a gas Gathering Line.

v. Any anticipated safety risks that will require the Operator to allow gas to escape, rather than being captured or combusted during drilling operations, pursuant to Rule 903.b.(2).

vi. A description of operational best practices that will be used to minimize Venting during active and planned maintenance allowed pursuant to Rule 903.d.(1).B.

vii. Procedures the Operator will employ to reduce the frequency of Well liquids unloading events.

viii. Anticipated volumes of liquids and gas production and a description of how separation equipment will be sized to optimize gas capture.

(2) **Verification.** Operators will verify that their facility has been connected to a gathering line by submitting a Form 10, Certificate of Clearance pursuant to Rule 219.

(3) **Compliance.** If an Operator does not connect its facility to a gathering line or otherwise put gas to beneficial use as described in the Operator's Form 2A or gas capture plan, the Director may require the Operator to shut in a Well until it is connected to a Gathering Line or the gas is put to beneficial use. The Operator may request a Commission hearing pursuant to Rule 503.g.(10), however, the Well will remain shut in until the Commission's hearing occurs.

904. EVALUATING CUMULATIVE IMPACTS

a. No later than January 15, 2022, and annually thereafter, the Director will report the following information to the Commission based on consultation with CDPHE and the Department of Natural Resources:

(1) A report from the Director about data gathered regarding anticipated and existing impacts in the Cumulative Impacts Data Evaluation Repository ("CIDER"), including but not limited to data regarding impacts to Wildlife Resources, including High Priority Habitat, and a comparison of water volume data reported pursuant to Rules 303.a.(5).B iii.ee and 431.b;

(2) Information from the Air Pollution Control Division ("APCD") or Air Quality Control Commission ("AQCC") regarding the current status of the Greenhouse Gas Pollution Reduction Roadmap and any initiatives developed by the APCD and AQCC to achieve Colorado's statewide greenhouse gas emission reductions, and the role of Oil and Gas Operations in achieving the reduction targets for the oil and gas sector;

(3) Information from the APDC or AQCC regarding the information reported pursuant to AQCC Regulation No. 7 in the oil and gas emissions inventories;

(4) Information regarding ambient air quality standard attainment, trends, and contributions from Oil and Gas Operations, including ground-level ozone ambient air quality standards;

(5) Information regarding evolving or new innovative technologies or measures, including technologies and measures employed by Operators during the prior year, that may provide innovative methods to reduce emissions or otherwise avoid, minimize, or mitigate adverse cumulative impacts to public health, safety, welfare, the environment, or wildlife resources;

(6) Any reports prepared or published by other Governmental Agencies or academic research institutions that provide relevant information about avoiding, minimizing, or mitigating adverse cumulative impacts to public health, safety, welfare, the environment, or wildlife resources;

(7) Any additional information that is requested by the Commission or that the Director determines is relevant to avoiding, minimizing, or mitigating adverse cumulative impacts to public health, safety, welfare, the environment, and wildlife resources; and

(8) Any recommendations for future rulemakings, guidance, work groups, or studies to address cumulative impacts to public health, safety, welfare, the environment, or wildlife resources and any air, water, soil, or biological resources based on the information presented pursuant to Rules 904.a.(1)–(7).

b. As a condition of approving an Oil and Gas Development Plan pursuant to Rule 307.b.(1), the Commission may require an Operator to participate in studies evaluating cumulative impacts of oil and gas development that is related to an Oil and Gas Location approved pursuant to the Oil and Gas Development Plan, or the impacts of that Oil and Gas Location.

(1) The studies may be conducted in consultation with CDPHE, CPW, the Public Utilities Commission, the Colorado Energy Office, or other third parties.

(2) Participation in the study may involve providing data, conducting investigations, performing monitoring, or other methods of gathering data, supplying data to the Director, or providing the Director or other authorized party access to a physical location. An Operator participating in a study will provide all data and other information gathered as part of the study to the Director upon request. Participation in a study will not require an Operator to fund the study, unless the Operator chooses to provide funding voluntarily.

c. The Commission may establish an informational docket on its own motion pursuant to Rule 503.a. Through the informational docket, the Commission may solicit general or specific information necessary and reasonable to evaluate the cumulative impacts of Oil and Gas Operations. Participation in the informational docket will not require payment of a docket fee or filing fee.

905. MANAGEMENT OF E&P WASTE

a. General Requirements.

(1) **Operator Obligations.** Operators will ensure that E&P Waste is properly stored, handled, transported, treated, recycled, or disposed to prevent threatened or actual adverse environmental impacts to air, water, soil, or biological resources, or to the extent necessary to ensure compliance with the concentration levels in Table 915-1, radiation control standards, and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(2) **Protecting Waters of the State.** Operators will conduct E&P Waste management activities, and construct and operate all Oil and Gas Locations, to protect the Waters of the State from adverse environmental impacts caused by E&P Waste.

(3) **Reuse and Recycling.** To encourage and promote waste minimization, Operators may propose plans for managing E&P Waste through beneficial use, reuse, and recycling by submitting a written management plan to the Director for approval on a Form 4, Form 15, or Form 28, Centralized E&P Waste Management Facility Permit. Such plans will describe, at a minimum:

A. The type(s) of waste;

B. The proposed volume and use of the waste;

C. The method of waste treatment and storage;

D. Recycled materials quality assurance;

E. Final disposition of the waste;

F. A copy of any certification or authorization that may be required by other laws and regulations;

G. A proposed timeline for reuse and recycling;

H. Beneficial use criteria;

I. Anticipated method of transporting waste; and

J. Any additional information requested by the Director.

(4) **Waste Management Plans.** Each Operator that generates E&P Waste as a result of their operations will prepare a comprehensive waste management plan detailing how the Operator will treat, characterize, manage, store, dispose, and transport all types of waste generated. The Director may require a waste management plan to include a description of proposed haul routes, including any applicable Local Government traffic requirements.

A. Operators will submit their waste management plans with their Form 2A pursuant to Rule 304.c.(11).

B. Operators will evaluate opportunities for reuse and recycling and may include a reuse and recycling plan, as described in Rule 905.a.(3) above, as part of the waste management plan.

C. If an Operator seeks to change its E&P Waste management practice, the Operator will update its waste management plan by submitting a revised waste management plan for the Director's approval or denial on a Form 4.

(5) Should evidence indicate that conditions at an active or closed Oil and Gas Location, Oil and Gas Facility, or Land Application site where produced Fluids and E&P Waste are currently or were previously generated, stored, treated, or disposed indicate contaminant concentrations in soils or Groundwater exceeding applicable standards, then the Commission authorizes the Director to require further investigation, Remediation, and Reclamation.

b. **E&P Waste Transportation.**

(1) **Off-Site Transportation Within Colorado.** Operators will only transport E&P Waste off-site within Colorado to facilities authorized by the Director, to permitted commercial waste disposal facilities, permitted commercial waste recycling facilities, or beneficial use sites approved to receive E&P Waste by CDPHE and the Relevant Local Government.

(2) **Off-Site Transportation Outside of Colorado.** Operators will only transport E&P Waste off-site for treatment or waste disposal outside of Colorado to facilities authorized and permitted by the appropriate regulatory agency in the receiving state. Operators will comply with the Rocky Mountain Low-level Radioactive Waste Board's Rules, as incorporated by reference in Rule 901.b.

(3) **Waste Generator Requirements.** Any Operator that generates E&P Waste that is transported off-site will maintain, for not less than 5 years, copies of each invoice, bill, or ticket, and such other records as necessary to document the requirements listed in Rules 905.b.(3).A–F. Such records will be signed by the transporter and provided to the Director upon request.

A. The date of the transport;

B. The identity of the waste generator;

C. The identity of the waste transporter;

D. The location of the waste pickup site;

E. The type and volume of waste; and

F. The name and location of the treatment or disposal site.

c. Produced Water.

(1) **Treatment of Produced Water.** Operators will treat produced water prior to placing it in a production pit to prevent crude oil, condensate, or hydrocarbon sheen from entering the Pit.

(2) **Produced Water Disposal.** Produced water may be disposed as follows:

A. Injection into a Class II UIC Well, permitted pursuant to the Commission's 800 Series Rules, or a Class I well permitted by EPA;

B. Evaporation/percolation in a properly permitted Pit at an Oil and Gas Location, operated in accordance with permit conditions that will not cause a violation of any applicable WQCC Regulation 41 numeric or narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b;

C. Disposal at permitted commercial facilities;

D. Discharging into Waters of the State under the following conditions pursuant to the Water Quality Control Act and all applicable regulations.

i. Operators will provide the Colorado discharge permit number, latitude and longitude coordinates pursuant to Rule 216.e of the discharge outfall, and sources of produced water on a Form 26, Source of Produced Water for Disposal, and will include a U.S. Geological Survey topographic map showing the location of the discharge outfall.

ii. If the discharge outfall is not located immediately at the receiving water body, the Operator will prevent surface impacts such as erosion or contamination that can result from the produced water flowing across the land surface.

iii. Produced water discharged pursuant to this Rule 905.c.(2).D may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water.

E. Evaporation in a properly lined Pit at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907.

(3) **Produced Water Reuse and Recycling.** Operators may reuse produced water for enhanced recovery, drilling, completion, and other approved uses in a manner consistent with existing water rights and in consideration of water quality standards and classifications established by the WQCC for Waters of the State, or any Point of Compliance established by the Director pursuant to Rule 914.

(4) **Mitigation.** Operators may use water produced during operation of an oil or gas Well to provide an alternative domestic water supply to Surface Owners within the oil or gas Field, pursuant to all applicable laws, including, but not limited to, obtaining the necessary approvals from the Water Quality Control Division for constructing a new "waterworks," as defined by § 25-1.5-203(1)(b)(II)(A), C.R.S. Any produced water not so used will be disposed of pursuant to Rules 905.c.(2) or (3). Providing produced water for domestic use within the meaning of this Rule 905.c.(4) will not constitute an admission by the Operator that the Well is dewatering or impacting any existing water well. The water produced will be to the benefit of the Surface Owner within the oil and gas Field and may not be sold for profit or traded.

(5) **Water Sharing Agreements.** Operators will submit agreements for sharing produced water for the Director's approval or denial no less than 60 days in advance of implementing the water sharing plan. The plan will be submitted as a waste management plan pursuant to Rule 905.a.(4).

d. **Drilling Fluids.**

(1) **Reuse and Recycling.** Operators may recycle drilling Pit contents for reuse at another drilling Pit that is properly permitted and operated pursuant to Rules 908, 909, & 910.

(2) **Treatment and Disposal.** Operators will treat or dispose of drilling Fluids through:

A. Injection into a Class II UIC Well permitted pursuant to the Commission's 800 Series Rules;

B. Disposal at a commercial Solid Waste Disposal facility; or

C. Land Treatment or Land Application at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907.

(3) **Additional Authorized Disposal of Water-Based Bentonitic Drilling Fluids.** Operators may dispose of water-based bentonitic drilling fluids through one of the following methods:

A. Drying and burial in Pits on Non-Crop Land, if:

i. The resulting concentrations will not exceed the concentration levels in Table 915-1; and

ii. The Director approves the Operator's plan for closing the Pit pursuant to a prior approved Form 27.

B. Land Application if permitted by a waste management plan approved by the Director pursuant to Rule 905.a.(4), and if the Operator complies with the following standards:

i. **Application Methods.** Acceptable methods of Land Application include, but are not limited to, Production Facility construction and maintenance, lease road maintenance, and offsite beneficial reuse, subject to Rule 905.a.(4).

ii. **Land Application Requirements.**

aa. The average thickness of water-based bentonitic drilling Fluid waste applied will be no more than 3 inches.

bb. Operators will incorporate the drilling Fluid waste through mechanical means into the uppermost soil horizon.

cc. The waste will be applied to prevent ponding or erosion and will be incorporated as a beneficial amendment into the native soils within 10 days of application.

dd. Operators will not apply water-based bentonitic drilling Fluids to Non-Crop Land.

ee. Prior to application, Operators will analyze water-based bentonitic drilling Fluid waste to ensure that concentrations of contaminants of concern in water-based bentonitic drilling Fluids do not exceed concentrations in Table 915-1.

ff. The results of sampling analysis demonstrating compliance with Table 915-1 will be provided to the Director upon request.

iii. **Surface Owner & Relevant Local Government Approval.** Operators will obtain written authorization from the Relevant Local Government, if required, and the Surface Owner prior to Land Application of water-based bentonitic drilling Fluids and provide the written authorization to the Director upon request.

iv. **Recordkeeping.** Operators will maintain records of the information listed in Rules 905.d.(3).B.iv.aa–cc for 5 years, pursuant to Rule 206.f. Operators will provide all such records to the Director within 5 days, upon request:

aa. The source of any water-based bentonitic drilling Fluids applied;

bb. The volume of any water-based bentonitic drilling Fluids applied; and

cc. The location where the Land Application of the water-based bentonitic drilling Fluid occurred.

v. **Operator Responsibility.** The Operator with control and authority over the Well(s) from which the water-based bentonitic drilling fluid wastes were obtained retains responsibility for the Land Application operation. All Operators will cooperate with the Director in responding to complaints regarding Land Application of water-based bentonitic drilling Fluids.

e. Oily Waste.

(1) **Treatment and Disposal.** Operators may treat or dispose of Oily Waste through one of the following methods:

A. Disposal at a commercial Solid Waste Disposal facility;

B. Land Treatment onsite pursuant to 905.e.(2); or

C. Land Treatment at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907.

D. Onsite treatment, for Oily Waste other than Tank bottoms, using alternative methods described on a Form 27 submitted to the Director for prior approval.

(2) **Land Treatment Requirements.**

A. Prior to commencing any Land Treatment, Operators will submit and obtain approval of a Form 27. The Form 27 will include, at a minimum:

i. A site diagram depicting the location of the planned Land Treatment area;

ii. The duration of the planned treatment; and

iii. The Operator's plan for final disposition of the treated Oily Waste.

B. Operators will adhere to the approved plan provided with the Form 27 and Rules 907 and 915 when performing Land Treatment.

C. Operators will remove free oil from the Oily Waste prior to Land Treatment.

D. Operators will spread Oily Waste evenly to prevent pooling, ponding, and runoff.

E. Operators will prevent Pollution of Stormwater Runoff, Groundwater, and surface water.

i. Operators will establish stormwater controls and use Best Management Practices to prevent contaminated stormwater from leaving the Land Treatment area.

ii. Operators will establish Land Treatment areas where contaminant mobility, soil type, or depth to Groundwater prevent downward migration of contaminants that would cause a violation of any WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

iii. Operators will establish Land Treatment areas a minimum of 200 feet from the ordinary high water mark of a surface water.

iv. The Director may require the use of a liner beneath the Land Treatment area as a condition of approval on the Form 27, as appropriate.

F. Operators will enhance biodegradation by routine disking, tilling, aerating, or addition of nutrients, microbes, water or other amendments, at a predetermined frequency pursuant to the approved Form 27.

G. When Operators incorporate land-treated Oily Waste in place or beneficially reuse it, the treated waste may not exceed the cleanup concentrations in Table 915-1, including inorganic constituents and metals.

H. Surface Owner Consent.

i. If an Operator intends to conduct Land Treatment in an area not being utilized for Oil and Gas Operations, the Operator will obtain the Surface Owner's consent to conduct the Land Treatment operations on the Surface Owner's property, and provide a copy of the signed agreement with the Surface Owner to the Director with the Form 27 prior to proceeding with Land Treatment.

ii. If an Operator intends to conduct Land Treatment on an approved Oil and Gas Location prior to completion of interim Reclamation or on the surface disturbance remaining after interim reclamation, the Operator will provide notice to the Surface Owner at least 30 days before commencing the Land Treatment. Notice will, at a minimum, include a site diagram depicting the location of the planned Land Treatment area, the duration of the planned treatment, and planned final disposition of the waste.

I. Operators will conduct Land Treatment in a manner that does not preclude compliance with Rules 1003 and 1004.

J. Operators will not conduct Land Treatment of Oily Waste on an Oil and Gas Location after the final Well has been plugged. Oily Waste will be treated or disposed pursuant to Rules 905.e.1.(A) or (C).

K. Operators will conduct Land Treatment in a manner that achieves compliance with Table 915-1 concentrations in three years or less. If the treated waste does not comply with Table 915-1 within three years of the date of Land Treatment, the Operator will submit a Form 28 at least 90 days in advance of the 3-year anniversary of the Land Treatment Form 27 approval date. Failure to comply with Table 915-1 in 3 years or to submit a Form 28 will result in the requirement to immediately remove and properly dispose any remaining Oily Waste pursuant to Rules 905.e.1.(A) or (C).

f. **Other E&P Waste.** Operators may treat and dispose other E&P Waste, including but not limited to workover Fluids, Tank bottoms, pigging wastes from Pipelines, and gas gathering, processing, and storage wastes through one of the following methods:

(1) Disposal at a commercial Solid Waste Disposal facility;

(2) Treatment at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907;

(3) Injection into a Class II UIC Well permitted pursuant to the Commission's 800 Series Rules; or

(4) An alternative method proposed in a waste management plan pursuant to Rule 905.a.(4) and approved by the Director.

g. **Drill Cuttings.** Operators will treat or dispose of drill cuttings through one of the following methods:

(1) **Oily Waste.** Operators will manage the following drill cuttings as Oily Waste pursuant to Rule 905.e:

A. Drill cuttings generated from oil-based drilling fluids;

B. Drill cuttings that exceed Table 915-1 concentrations for organic compounds in soil; and

C. Drill cuttings that have not been sampled and analyzed to demonstrate compliance with Table 915-1 for organic compounds in soil.

(2) **Drill Cuttings.** Operators will demonstrate compliance with Table 915-1 through sampling and analysis. Management of drill cuttings that exceed Table 915-1 for constituents listed under soil suitability for Reclamation by the methods listed below is subject to prior approval by the Director, pursuant to Rule 915.b. Operators may manage drill cuttings that comply with Table 915-1, are not Oily Waste, and are generated using water-based bentonitic drilling Fluids through one of the following methods:

A. Disposal at a commercial Solid Waste Disposal facility;

B. Disposal at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907;

C. Subject to Surface Owner approval, Land Application as a beneficial soil amendment to native soil subject to a waste management plan approved pursuant to Rule 905.a.(4).

D. If permitted by Rule 1003.d, and subject to Surface Owner approval, drying and burial in on-location drilling Pits that are documented with a Form 27 submitted for prior Director approval for closure of the Pit; or

E. Subject to Surface Owner approval, and prior Director approval of a Form 27, burial in a Cuttings Trench.

906. MANAGEMENT OF NON-E&P WASTE

a. Certain wastes generated by Oil and Gas Operations that do not meet the 100 Series definition of E&P Waste are regulated as solid or hazardous wastes by CDPHE's Solid and Hazardous Waste Commission ("SHWC"). Operators will properly identify and dispose of these wastes pursuant to applicable state and federal regulations.

b. The SHWC Hazardous Waste Regulations, as incorporated by reference in Rule 901.b, require that a hazardous waste determination be made for any non-E&P solid waste. Operators will comply with all hazardous waste storage, treatment, and disposal requirements in the SHWC's Hazardous Waste Regulations, as incorporated by reference in Rule 901.b.

c. All non-hazardous/non-E&P Wastes are considered solid waste. Operators will comply with all storage, treatment, and disposal requirements in the SHWC's Solid Waste Regulations, as incorporated by reference in Rule 901.b.

d. Operators will not burn or bury non-E&P Waste on Oil and Gas Locations.

907. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

a. Applicability. Operators may establish non-commercial, Centralized E&P Waste Management Facilities for the treatment, disposal, recycling, or beneficial reuse of E&P Waste. This Rule 907 applies only to non-commercial facilities, which means the Operator does not represent itself as providing E&P Waste management services to third parties, except as part of a unitized area or joint operating agreement or in response to an emergency. Centralized E&P Waste Management Facilities may include components such as Land Treatment or Land Application sites, Pits, and recycling equipment.

b. Permit Requirements. Before any Operator commences construction of a Centralized E&P Waste Management Facility, the Operator will file and obtain the Director's approval of an application on a Form 28, Centralized E&P Waste Management Facility Permit, and pay a filing fee established by the Commission (see Appendix III). The Operator will submit a Form 28 application at the same time it submits any permit applications required by the Commission's 300 Series Rules, if any, including an Oil and Gas Development Plan or a Form 2A. In addition, the Form 28 will contain the following:

(1) The name, address, phone and email address of the Operator, and a designated contact person.

(2) The name, address, phone number, email address, and written authorization of the Surface Owner of the site, if not the Operator.

(3) The legal description of the site.

(4) A general topographic, geologic, and hydrologic description of the site, including immediately adjacent land uses and a topographic map of a scale no less than 1:24,000 showing the location and the average annual precipitation and evaporation rates at the site.

(5) Centralized E&P Waste Management Facility Siting Requirements.

A. A site plan showing drainage patterns and any diversion or containment structures, and facilities such as roads, fencing, tanks, Pits, buildings, and other construction details.

B. Scaled drawings of entire sections containing the proposed facility. The field measured distances from the nearer north or south and nearer east or west section lines will be measured at 90 degrees from said section lines to facility boundaries and referenced on the drawing. A survey will be provided including a complete description of established monuments or collateral evidence found and all aliquot corners.

C. The facility will be designed to control public access, prevent unauthorized vehicular traffic, provide for site security both during and after operating hours, and prevent illegal dumping of wastes. Appropriate measures will also be implemented to prevent access to the Centralized E&P Waste Management Facility by wildlife or domestic animals.

D. Centralized E&P Waste Management Facilities will have a fire lane of at least 10 feet in width around the perimeter of the active treatment areas and within the facility fencing. In addition, a buffer zone of at least 10 feet will be maintained within the perimeter fire lane.

E. Surface water diversion structures, including but not limited to berms and ditches, will be constructed to accommodate a 100-year, 24-hour storm event. The facility will be designed and constructed with a run-on control system to prevent flow onto the facility during peak discharge and a run-off control system to contain the water volume from a 25-year, 24-hour storm event.

F. Operators will provide evidence that they have complied with any Relevant Local Government land use regulations and facility siting or construction or operation requirements.

G. Operators will not construct new Centralized E&P Waste Management Facilities within 2,000 feet of the nearest Building Unit or High Occupancy Building Unit, unless all Building Unit owners and tenants within 2,000 feet consent to a closer location.

(6) **Waste Profile.** For each type of waste, Operators will estimate the amounts to be received and managed by the facility on a monthly average basis. For each waste type to be treated, Operators will complete a characteristic waste profile, which will include analysis of representative waste samples by an accredited laboratory.

(7) **Facility Design and Engineering.** Facility design and engineering data, incorporating Best Management Practices, including plans and elevations, design basis, calculations, and process description. Facility design, engineering, and as-constructed plans will be reviewed and stamped by a Colorado Professional Engineer ("P.E.").

A. Geologic data, including, but not limited to:

i. Type and thickness of unconsolidated soils;

ii. Type and thickness of consolidated bedrock, if applicable;

iii. Local and regional geologic structures; and

iv. Any Geologic Hazards that may affect the design and operation of the facility.

B. Hydrologic data, including, but not limited to:

i. Water wells within 1 mile of the site boundary including, but not limited to, information such as well construction details, total depth, static water level, screened interval(s), yields, and Aquifer name(s).

ii. Surface water features within 2 miles;

iii. Site location in relation to the Floodplain of nearby surface water features;

iv. Depth to Groundwater, including specifically identifying the shallowest unconfined Groundwater and any underlying Groundwater formations;

v. Existing quality of the shallowest Groundwater;

vi. Hydrologic properties of the shallowest Groundwater at the location including flow direction, flow rate, and potentiometric surface; and

vii. An evaluation of the potential for impacts to nearby surface water and Groundwater.

C. Engineering data, including, but not limited to:

i. Type and quantity of material required for use as a liner, including design components;

ii. Location and depth of cut for liners;

iii. Design of leak detection system for Pits or other containment systems;

iv. Location, dimensions, and grades of all surface water diversion structures;

v. Location and dimensions of all surface water containment structures; and

vi. Location of all proposed facility structures and access roads.

(8) **Operating Plan.** An operating plan, incorporating Best Management Practices, including, but not limited to:

A. A detailed description of the method of treatment, loading rates, and application of nutrients and soil amendments;

B. Dust and moisture control;

C. Sampling;

D. Inspection and maintenance;

E. Emergency response;

F. Recordkeeping;

G. Site security;

H. Hours of operation;

I. Stormwater management plan;

J. Noise, visual impacts, and odor mitigation; and

K. Final disposition of waste. If the Operator intends to beneficially reuse treated waste, the Operator will describe the reuse and method of product quality assurance.

(9) Groundwater Monitoring.

A. Water Wells. Operators will collect water samples from water wells known to the Operator or registered with the Colorado State Engineer, following all protocols established by Rule 615, except that the Operator will collect water samples from known water wells within 1 mile of the proposed Centralized E&P Waste Management Facility. An Operator may request an exception from the requirements of this Rule 907.b.(9).A by submitting a Form 4 pursuant to Rule 615.c.

B. Site-Specific Monitoring Wells.

i. As a condition of approval, the Director may require the Operator to install site-specific monitoring wells to ensure compliance with the concentration levels in Table 915-1 and WQCC Regulation 41, as incorporated by reference in Rule 901.b, by establishing Points of Compliance.

ii. All monitoring well construction must be completed pursuant to the State Engineer's Water Well Construction and Permitting Rules, as incorporated by reference in Rule 901.b.

iii. Where monitoring is required, the direction of flow, Groundwater gradient, and quality of water will be established by the installation of a minimum of 3 monitor wells, including an up-gradient well and 2 down-gradient wells that will serve as Points of Compliance, or other methods authorized by the Director.

iv. The Operator will propose for prior Director approval monitoring schedules, reporting schedules, and appropriate analyte lists.

(10) Surface Water Monitoring. Where applicable, the Director will require baseline and periodic surface water monitoring to ensure compliance with WQCC surface water standards and classifications, including narrative standards. Operators will use reasonable good faith efforts to obtain access to such surface water for the purpose of collecting water samples. If access cannot be obtained, then the Operator will notify the Director of the surface water for which access was not obtained and sampling of such surface water by the Operator will not be required.

(11) Contingency Plan. A contingency plan that describes the emergency response operations for the facility, 24-hour contact information for the person who has authority to initiate emergency response actions, contact information of local emergency response authorities, and an outline of responsibilities under any joint operating agreement regarding maintenance, operations, closure, and monitoring of the facility.

c. Permit Review.

(1) Within 90 days of the submission for a Form 28, the Director will issue a determination about whether the Form 28 application is complete.

(2) The Director may approve the Centralized E&P Waste Management Facility permit if it protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Director 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 the extent necessary to ensure compliance with the concentration levels in Table 915-1, or WQCC Regulation 41 Groundwater standards and classifications, as incorporated by reference in Rule 901.b.

(3) The Director may deny a Centralized E&P Waste Management Facility permit if it does not adequately protect and minimize impacts to public health, safety, welfare, the environment, and wildlife resources.

d. Financial Assurance. The Operator of a Centralized E&P Waste Management Facility will submit for the Director's approval such Financial Assurance as required by Rule 704 prior to the Director issuing the operating permit.

e. Facility Modifications. Throughout the life of the facility, the Operator will submit proposed modifications to the facility design, operating plan, permit data, or permit conditions to the Director for prior approval through a Form 4.

f. Permit Expiration. The Form 28 will expire 3 years after approval if the Operator has not commenced construction of the permitted facility.

g. Annual Permit Review. To ensure compliance with permit conditions and the Commission's Rules, the facility permit will be subject to an annual review by the Director. To facilitate this review, the Operator will submit an annual report summarizing operations, including the types and volumes of waste handled at the facility. The Director may require additional information.

h. Closure.

(1) **Preliminary Closure Plan.** A general preliminary plan for closure will be submitted with the Form 28. The preliminary closure plan will include, but not be limited to:

A. A general plan for closure and Reclamation of the entire facility, including a description of the activities required to decommission and remove all equipment, close and reclaim Pits, dispose of or treat residual waste, collect samples as needed to verify compliance with soil and Groundwater standards, implement post-closure monitoring, and complete other Remediation, as required.

B. An estimate of the cost to close and reclaim the entire facility and to conduct post-closure monitoring. Cost estimates will be subject to review by the Director to verify that the financial assurance provided pursuant to Rules 907.d and 704 is appropriate.

(2) **Final Closure Plan.** The Operator will submit a detailed Form 27 at least 60 days prior to closure for approval or denial by the Director. The workplan will include, but not be limited to, a description of the activities required to decommission and remove all equipment, close and reclaim Pits, dispose of or treat residual waste, collect samples as needed to verify compliance with soil and Groundwater standards, implement post-closure monitoring, and complete other Remediation, as required.

908. PIT PERMITTING/REPORTING REQUIREMENTS

a. Operators will submit a Form 15, Earthen Pit Report/Permit to the Director for review and approval prior to constructing any of the following:

(1) All Production Pits;

(2) Special Purpose Pits except those listed in Rules 908.c.(1) or (2);

(3) Drilling Pits; and

(4) Multi-Well Pits, including those located at Centralized E&P Waste Management Facilities.

b. Operators will submit a Form 15, to the Director for review and approval prior to enlarging or otherwise modifying an existing properly permitted Pit.

c. Operators will submit a Form 15 within 30 days after constructing:

(1) Emergency Pits, Plugging Pits, and Workover Pits if they are used in the initial phase of an emergency response; and

(2) Cuttings Trenches approved on a Form 2A.

d. In order to allow adequate time for Pit permit review and approval, Operators will submit a Form 15 at the same time they submit a Form 2A or Oil and Gas Development Plan. The Director may condition approval of the Form 15 upon compliance with additional terms, provisions, or requirements necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Director may deny a Form 15 if the Director determines it does not provide necessary and reasonable standards to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Notwithstanding the foregoing, no Form 15 will be approved until the associated Form 2A or Oil and Gas Development Plan is approved.

909. PITS – CONSTRUCTION AND OPERATION

a. Operators will ensure that the Pits they operate are:

(1) Properly permitted through a Form 15 approved by the Director, or registered in their names with an active Pit Facility ID;

(2) Accurately mapped; and

(3) Listed according to current facility records in the Commission's database. Operators may update facility records using a Form 15.

b. Operators will construct, maintain, and operate Pits used for exploration and production of oil and gas in a manner that protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Operators will operate and maintain Pits and Pit liners to prevent Spills and Releases.

c. Operators will construct, monitor, and operate Pits to provide for a minimum of 2 feet of freeboard at all times between the top of the Pit wall at its point of lowest elevation and the Fluid level of the Pit. Operators will employ a method of monitoring and maintaining the freeboard. Operators will report any unauthorized Release of Fluids from a Pit pursuant to Rule 912.

d. Operators will not store oil or any other produced liquid hydrocarbon substance in earthen Pits or reservoirs, except in emergencies where such substances cannot be otherwise contained. Operators will remove the oil or produced hydrocarbons as soon as the emergency is controlled. Operators will submit a Form 15 for the Director's approval within 30 days of the emergency, pursuant to Rule 908.c.

e. No liquid hydrocarbons may be present in a Pit unless the Pit is specifically permitted as a Skimming/Settling ("Skim") Pit.

(1) Immediately upon discovery or notification, Operators will remove any accumulation of oil or condensate, including free product or hydrocarbon sheen, from a Pit. If the Operator is unable to immediately remove the accumulation, the accumulation will be removed within 24 hours of discovery.

(2) Operators will use skimming, steam cleaning of exposed liners, or other safe and legal methods as necessary to maintain Pits in clean condition and to control hydrocarbon odors.

(3) If an Operator allows oil or condensate (free product or sheen) to accumulate in a Pit, then the Director may revoke the Operator's Form 15 and require the Operator to close and remediate the Pit.

f. Operators will fence and net or install CPW-approved exclusion devices on all new Pits pursuant to Rule 1202.a.(4).

g. Operators may use Multi-Well Pits for a period of no more than 3 years, unless:

(1) The Operator obtains a permit to operate the Multi-Well Pit pursuant to Rule 907 at a Centralized E&P Waste Management Facility;

(2) The Multi-Well Pit is located in Huerfano or Las Animas Counties and was constructed prior to May 1, 2011; or

(3) The Multi-Well Pit is located in Logan, Morgan, Washington, and Yuma Counties and was constructed prior to May 1, 2013.

(4) Based on evidence of risks to public health, safety, welfare, the environment, or wildlife resources, the Director may require an Operator to line, net, cover, fence, or close an existing Multi-Well Pit that is subject to Rules 909.g.(2) & (3), or submit a Form 28 for such a Multi-Well Pit.

h. Operators will treat produced water pursuant to Rule 905.c.(1) before placing it in a Production Pit.

i. Operators will utilize appropriate biocide treatments to control bacterial growth and related odors.

j. **Produced Water Quality Analyses.** Beginning January 15, 2021, Operators will submit an initial water quality analysis for produced water for each Well from which produced water is placed into a permitted or registered Pit, including Pits that were constructed prior to January 15, 2021.

(1) The water sample will be analyzed for the following:

A. pH;

B. Specific conductance;

C. Total dissolved and suspended solids (TDS and TSS);

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

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

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

G. Other elements (barium, boron, selenium, and strontium);

H. Naphthalene;

I. Total petroleum hydrocarbons ("TPH") as total volatile hydrocarbons (C_6 to C_{10}) and total extractable hydrocarbons (C_{10} to C_{36});

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

K. Radium (^{226}Ra and ^{228}Ra).

(2) **Subsequent Sampling and Analysis.** After initial sampling, Operators will collect and analyze subsequent samples at the following frequencies:

A. For lined Pits, Operators will collect and analyze a second confirmation sample during the period between 33 and 39 months after the initial sampling and analysis;

B. For unlined Pits:

i. Operators will collect and analyze samples on an annual basis after the initial sampling and analysis;

ii. If subsequent sampling and analysis indicates stable water quality over time, the Operator may request relief from further subsequent sampling and analysis by submitting a Form 4, which the Director will review and approve or deny;

C. For all Pits, Operators will collect and analyze a subsequent sample for any new Well that contributes water to the Pit;

D. For all Pits, Operators will collect and analyze a subsequent sample any time the Operator or Director has reason to believe the water quality in the Pit has changed; and

E. For all Pits, if subsequent sampling and analysis indicates variable water quality, the Director may require more frequent or additional sampling.

(3) Operators will submit all water quality analysis data using a Form 43, Analytical Sample Submittal, and will include suitable electronic data deliverable generated by the laboratory and PDF of lab reports within 3 months of sample collection. Results for the initial samples collected pursuant to Rule 909.j.(1) will be submitted no later than July 15, 2022, or prior to Pit closure, whichever is earlier.

(4) Operators will collect samples according to standard environmental procedures.

(5) Operators will analyze samples in an accredited laboratory using established methodologies. For those analytes with Groundwater threshold concentrations listed in WQCC Regulation 41, as incorporated by reference in Rule 901.b, the analytical technique will be capable of achieving, and will achieve, reporting limits at concentrations less than the WQCC Regulation 41 thresholds in the matrix submitted. The Director may review the analytical standard used for each analyte and may request the analysis be run by a different method.

(6) As an alternative to the sampling required by Rules 909.j.(1)–(5) the Operator transporting produced water produced from the same formation(s) in the same Field or unit to the same Pit may submit a Form 4 to request the Director's approval for an alternative sampling program to consolidate the number of samples required from the same formation(s).

910. PIT LINING REQUIREMENTS AND SPECIFICATIONS

a. Except for Cuttings Trenches and Pits constructed as an initial emergency response measure pursuant to Rule 908.c.(1), all Pits constructed after January 15, 2021 will be lined.

b. **Skim Pits.** Operators will not construct new Skim pits. All existing Skim Pits, regardless of date of construction, will be lined. For any unlined Skim Pits in existence on January 15, 2021, the

Operator will submit a Form 27 outlining the Operator's plan to delineate and remediate any associated impacts and a plan to either properly line or close the Pit. The Form 27 for an unlined Skim Pit must be submitted to the Director by April 1, 2021. If the Pit will be lined and returned to service, the Operator will also submit and obtain the Director's approval of a Form 15.

c. Operators will construct all Pits according to the following specifications:

(1) Materials used in lining Pits will be of a synthetic material that is impervious, has high puncture and tear strength, has adequate elongation, and is resistant to deterioration by ultraviolet light, weathering, hydrocarbons, aqueous acids, alkali, fungi, or other substances in the produced water.

(2) All Pit lining systems will be designed, constructed, installed, and maintained in accordance with the manufacturers' specifications and good engineering practices. Operators will maintain records demonstrating that the Operator followed manufacturers' specifications, and provide them to the Director upon request.

(3) Field seams will be installed and tested in accordance with manufacturer specifications and good engineering practices. Operators will maintain testing results, repair documentation (including the dates of tests and repairs), and provide them to the Director upon request.

d. Operators will construct all Pits, except those at Centralized E&P Waste Management Facilities, according to the following specifications:

(1) Liners will have a minimum thickness of 24 mils. The synthetic or fabricated liner will cover the bottom and interior sides of the Pit with the edges secured with at least a 12-inch deep anchor trench around the Pit perimeter. The anchor trench will be designed to secure, and prevent slippage or destruction of, the liner materials.

(2) The foundation for the liner will be constructed with material containing no sharp rocks, debris or other material that could puncture the liner. The foundation for the liner will have a minimum thickness of 12 inches after compaction, cover the entire bottom and interior sides of the Pit, and be constructed so that the hydraulic conductivity will not exceed 1.0 x 10^{-7} cm/sec after testing and compaction. Operators will maintain compaction and permeability test results measured in the laboratory and field and provide the results to the Director upon request.

(3) As an alternative to the soil foundation described in Rule 910.d.(2), Operators may construct the foundation with bedding material that exceeds a hydraulic conductivity of 1.0 x 10^{-7} cm/sec, if a double synthetic liner system is used. However, the bottom and sides of the Pit will be padded with soil or synthetic matting type material and will be free of sharp rocks or other material that are capable of puncturing the liner. Each synthetic liner will have a minimum thickness of 24 mils.

e. Operators will construct Pits used at Centralized E&P Waste Management Facilities according to the following specifications:

(1) Liners will have a minimum thickness of 60 mils. The synthetic or fabricated liner will cover the bottom and interior sides of the Pit with the edges secured with at least a 12-inch deep anchor trench around the Pit perimeter or in accordance with the liner manufacturer's specifications. The anchor trench will be designed to secure, and prevent slippage or destruction of, the liner materials.

(2) The foundation for the liner will be constructed with material containing no sharp rocks, debris, or other material that could puncture the liner. The foundation for the liner will have a minimum thickness of 24 inches after compaction, cover the entire bottom and interior sides of the Pit, and be constructed so that the hydraulic conductivity will not exceed 1.0 x 10^{-7} cm/sec after testing and compaction. Operators will maintain compaction and permeability test results measured in the laboratory and field and provide them to the Director upon request.

(3) As an alternative to the soil foundation described in Rule 910.e.(2), Operators may use a secondary liner consisting of a geosynthetic clay liner, which is a manufactured hydraulic barrier typically consisting of bentonite clay or other very low permeability material, supported by geotextiles or geomembranes, which are held together by needling, stitching, or chemical adhesives.

(4) As an alternative to the soil foundation described in Rule 910.e.(2), Operators may use a double synthetic liner system. However, the bottom and sides of the Pit will be padded with soil or synthetic matting type material and will be free of sharp rocks or other materials that are capable of puncturing the liner. Each synthetic liner will have a maximum thickness of 60 mils.

(5) All Pits will be constructed and operated with a leak detection system.

f. The Director may require the use of additional liners or a leak detection system for the Pit or other equivalent protective measures, including but not limited to, increased recordkeeping requirements, monitoring systems, and underlying gravel filled sumps and lateral systems. In making such a determination, the Director will consider the site-specific information provided by the Operator, including but not limited to surface and subsurface geology, the presence and depth to Groundwater, the quality of the produced water, the hydraulic conductivity of the surrounding soils, the distance to surface water and water wells, and the type of liner.

911. CLOSURE OF OIL AND GAS FACILITIES

a. Operators will close all Oil and Gas Facilities, including Drilling Pits and Cuttings Trenches, in accordance with an approved Form 27.

(1) Operators will obtain the Director's approval of the Form 27 prior to conducting any investigation or closure operations.

(2) The Form 27 will include a description of the proposed investigation and Remediation activities pursuant to Rule 913.

(3) Operators will close and remediate Emergency Pits as soon as the initial phase of emergency response operations is complete or any process Upset Conditions are controlled.

(4) Oil and Gas Facility closure pursuant to this Rule 911.a will be at the time of final site closure, Plugging and Abandonment, or decommissioning, unless the Director determines that a substantive change to the site requires a Form 27, or a reportable Spill or an historic impact is discovered during facility operation or removal.

b. **Discovery of a Spill or Release During Closure.** If an Operator discovers a Spill or Release during closure operations, the Operator will report the Spill or Release on a Form 19, Spill/Release Report, pursuant to Rule 912.

c. **Pit Closure.**

(1) **Pit Evacuation.** Operators will treat or dispose of E&P Waste pursuant to Rule 905 prior to backfilling and site Reclamation.

(2) Operators will collect a sufficient number of representative samples from locations beneath a Pit to demonstrate that no leakage of managed fluids has occurred. Operators will ensure that any soil left in place meets the cleanup concentrations listed in Table 915-1.

(3) Liner Disposal.

A. Synthetic Liner Disposal. Operators will remove and dispose of synthetic liners pursuant to all state and federal requirements for Solid Waste Disposal.

B. Constructed Soil Liners. Operators may remove constructed soil liner material for treatment or disposal. Alternatively, if an Operator leaves the constructed soil liner material in place, the Operator will rip the material and mix it with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and Groundwater flow. Operators will demonstrate that the resulting material meets cleanup concentrations for contaminants of concern listed in Table 915-1.

912. SPILLS AND RELEASES

a. General.

(1) Immediately upon discovering any Spills or Releases of E&P Waste, produced Fluids, or unauthorized Releases of natural gas that meet the criteria of Rules 912.b.(1).H, I, or J, regardless of size or volume, Operators will control and contain the Spill or Release to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) Operators will investigate, clean up, and document impacts resulting from Spills and Releases as soon as the impacts are discovered.

(3) The Director may require the Operator to perform any action the Director determines to be necessary and reasonable to prevent or mitigate adverse impacts on any air, water, soil, or biological resource caused by a Spill or Release.

(4) Operators will document and maintain records to demonstrate compliance with the concentration levels in Table 915-1, and, if surface water or Groundwater are impacted, WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(5) For any Spills or Releases that do not meet the reporting requirements of Rule 912.b, Operators will document cleanup efforts and provide documentation of the cleanup to the Director upon request.

b. Reporting Spills or Releases of E&P Waste, Gas, or Produced Fluids.

(1) Report to the Director. Operators will submit an initial report ("24 Hour Notification") of a Spill or Release of E&P Waste, natural gas, or produced Fluids that meet any of the following criteria to the Director verbally, via electronic mail, or on a Form 19, Spill/Release Report – Initial within 24 hours of discovery, unless otherwise specified below.

A. A Spill or Release of any size that impacts or threatens to impact any Waters of the State, Public Water System, residence or occupied structure, livestock, wildlife, or publicly-maintained road;

B. A Spill or Release in which 1 Barrel or more of E&P Waste or produced Fluids is spilled or released outside of berms or other secondary containment;

C. A Spill or Release of 5 Barrels or more of E&P Waste or produced Fluids regardless of whether the Spill or Release is completely contained within berms or other secondary containment.

D. Within 6 hours of discovery, a Grade 1 Gas Leak. For a Grade 1 Gas Leak from a Flowline, the Operator also must submit the Form 19 – Initial, document number on a Form 44, Flowline Report, for the Grade 1 Gas Leak.

E. The discovery of 10 cubic yards or more of impacted material resulting from a current or historic Spill or Release. Discovery and reporting will not be contingent upon confirmation samples demonstrating exceedance of Table 915-1 standards.

F. The discovery of impacted Waters of the State, including Groundwater. Discovery and reporting will not be contingent upon confirmation samples demonstrating exceedance of Table 915-1 standards. The presence of free product or hydrocarbon sheen on Groundwater or surface water is reportable. The presence of contaminated soil in contact with Groundwater or surface water is reportable.

G. A suspected or actual Spill or Release of any volume where the volume cannot be immediately determined, including a Spill or Release of any volume that daylights from the subsurface.

H. A Spill or Release resulting in vaporized hydrocarbon mists that leave the Oil and Gas Location or Off-Location Flowline right of way from an Oil and Gas Location and impacts or threatens to impact off-location property.

I. A Release of natural gas that results in an accumulation of soil gas or gas seeps.

J. A Release that results in natural gas in Groundwater.

(2) The 24 Hour Notification to the Director will include, at a minimum,

A. The specific location of the Spill or Release, including latitude and longitude;

B. Certification that the Operator provided additional party notifications as required by Rules 912.b.(7)–(10), below;

C. A description of any threat to Waters of the State, Public Water Systems, residences or occupied structures, livestock, wildlife, air quality, or publicly-maintained roads from the Spill or Release; and

D. Any information available to the Operator about the type and volume of Fluid or waste involved, including whether it is controlled or uncontrolled at the time of the 24 Hour Notification.

(3) If the Operator did not submit the 24 Hour Notification through a Form 19 – Initial, the Operator will submit a Form 19 – Initial no less than 72 hours after discovery of the Spill or Release unless the Director extends the timeframe in writing.

(4) In addition to the Form 19 – Initial, the Operator will file a Form 19 – Supplemental not more than 10 days after the Spill or Release is discovered that includes:

A. A topographic map showing the governmental section and location of the Spill or Release, or an aerial photograph showing the location of the specific Spill or Release site.

B. All pertinent information about the Spill or Release known to the Operator that has not been reported previously, including photo documentation showing the source of the Spill or Release, the impacted area, and initial cleanup activity; and

C. Information relating to the initial mitigation, site investigation, and Remediation measures conducted by the Operator.

D. Global Positioning System data that meets the requirements of Rule 216 if latitude and longitude data provided pursuant to Rule 912.b.(2).A did not meet the requirements of Rule 216.

(5) The Director may require any Form 19 – Supplemental reports or information the Director determines are necessary.

(6) No later than 90 days after a Spill or Release is discovered, the Operator will have submitted, and obtained the Director's approval of either:

A. A Form 19 – Supplemental requesting closure pursuant to Rule 913.h and supported by adequate documentation to demonstrate that the Spill or Release has been fully cleaned up and complies with Table 915-1; or

B. A Form 27 if any of the criteria listed in Rules 912.b.(6).B.i–iii apply. If Remediation will continue under an approved Form 27, the Operator will also submit a Form 19 – Supplemental which requests closure of the Spill or Release and includes the Remediation project number assigned by the Director.

i. A Form 27 is required by the Commission's Rules;

ii. Cleanup or Remediation will continue for longer than 90 days after the Spill or Release was discovered; or

iii. The Director requests a Form 27.

(7) **Notification to Local Governments.** At the same time the Operator makes the 24 Hour Notification, the Operator will provide verbal or written notification to the entity with jurisdiction over emergency response within the local municipality if the Spill or Release occurred within a municipality or the local county if the Spill or Release did not occur within a municipality. The notification will include, at a minimum, the information listed in Rule 912.b.(2).

(8) **Notification to the Surface Owner.** The Operator will provide verbal or written notification to the affected Surface Owner or the Surface Owner's appointed tenant concurrent with providing the 24 Hour Notification.

A. If the Surface Owner cannot be reached within 24 hours, the Operator will continue to make good faith efforts to notify the Surface Owner until notice has been provided.

B. The verbal or written notification will include, at a minimum, the information listed in Rule 912.b.(2).

C. The Operator will document the notification including the name of the person contacted, phone number or email of contact, date, and time on the Form 19 – Initial and update the information as necessary on the Form 19 -- Supplemental.

(9) **Report to Environmental Release/Incident Report Hotline.** Operators will report a Spill or Release of any size that impacts or threatens to impact surface waters to the Director and to the Environmental Release/Incident Report Hotline (1-877-518-5608). Spills and Releases that impact or threaten a Public Water System intake, as described in Rules 411.a.(4) & 411.b.(5), will be verbally reported to the emergency contact for that facility concurrent with providing the 24 Hour Notification to the Director pursuant to Rule 912.b.(1).

(10) At the same time the Operator submits a Form 19 – Initial, the Operator will provide verbal or written notification to CPW if the Spill or Release occurred within 300 feet of surface Waters of the State, or within High Priority Habitat.

(11) **Reporting Chemical Spills or Releases.** Operators will report Chemical Spills and Releases pursuant to applicable state and federal laws, including the Emergency Planning and Community Right-to-Know Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Oil Pollution Act, and the Clean Water Act.

c. Remediation of Spills or Releases.

(1) The Director may require Operators to submit a Form 27 if the Director identifies any threatened or actual adverse impacts to any air, water, soil, wildlife, or other environmental resource from a Spill or Release, or if necessary to ensure compliance with the concentration levels in Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(2) Not including initial emergency response operations, the Operator will notify and consult with any affected Surface Owners, or the Surface Owner's appointed tenant, prior to commencing operations to remediate a Spill or Release in an area not being utilized for Oil and Gas Operations. It is the Operator's burden to timely notify and negotiate access with the Surface Owner. Failure to do so will not relieve the Operator from its responsibility to commence or complete Remediation approved by the Director.

d. Spill and Release Prevention.

(1) Operators will determine and document the cause of a Grade 1 Gas Leak or Spill or Release of E&P Waste or produced Fluids. After identifying the cause, Operators will implement measures to prevent Spills or Releases due to similar causes in the future, and document all changes made.

(2) The Director may take enforcement action if a Spill occurs at any site subject to control of the same Operator as a result of similar causes identified in Rule 912.d.(1).

(3) Operators will provide documentation of the Spill or Release evaluation and any steps taken to prevent Spills or Releases due to similar causes in the future to the Director upon request.

e. Suspected Spill or Release Closure.

(1) Operators will submit a Supplemental Form 19 providing documentation that any suspected Spill or Release reported pursuant to Rule 912.b.(1).G did not exceed any applicable reporting thresholds. The Operator will clean up any actual Spill below the reporting threshold of Rule 912.b pursuant to the requirements of Rule 912.a.(5).

(2) If the suspected Spill or Release reported pursuant to Rule 912.b.(1).G did in fact exceed any reporting threshold identified in Rule 912.b.(1), the Operator will clean up the Spill pursuant to the requirements of Rule 912.c.

f. Changes of Operator. Within 60 days of the Director's approval of a Form 9, Transfer of Operatorship – Subsequent pursuant to Rule 218.e, the Buying Operator will submit a supplemental Form 19 designating the responsible Operator for each open Spill and Release.

913. SITE INVESTIGATION, REMEDIATION, AND CLOSURE

a. Applicability. This Rule 913 applies to the investigation, Remediation, and reporting required for Spills and Releases, Remediation projects, and decommissioning of Oil and Gas Facilities. All site investigation, Remediation, and closure operations will be conducted in accordance with the Commission's Rules, including the Commission's 1000 Series Rules.

b. General Site Investigation and Remediation Requirements.

(1) Site Investigation and Remediation Workplan. Operators will submit and obtain the Director's approval of a Form 27 whenever it is required by the Commission's Rules, prior to commencing the operations addressed by the Form 27.

(2) Sampling and Analyses. Operators will conduct sampling and analysis of soil and Groundwater pursuant to Rule 915 to determine the horizontal and vertical extent of any contamination in excess of the cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

A. Sampling and analyses will be required to profile E&P Waste, delineate extent of contamination, and confirm compliance with applicable standards upon completion of Remediation.

B. Laboratory method detection limits must be less than or equal to Table 915-1 or WQCC Regulation 41 standards, as incorporated by reference in Rule 901.b.

C. Composite sample results may be submitted for preliminary analysis and waste profiling. Discrete sample results will be required for confirmation sampling.

(3) Management of Investigation-Derived Waste. Investigation-Derived Waste will be managed pursuant to Rules 905 or 906.

(4) Pit Evacuation. Prior to site investigation and Remediation, E&P Waste will be treated or disposed pursuant to Rule 905.

(5) Remediation.

A. Remediation will be performed in a manner that reduces or removes contamination that exceeds the cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, and that protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

B. When conducting Remediation activities, Operators will conform to the following standards:

i. Operators will fence or cover open excavations to prevent access when sites are not attended.

ii. Operators will protect topsoil, consistent with the Commission's 1000 Series Rules.

iii. Operators will minimize surface disturbance.

iv. Operators will properly store, handle, and manage all E&P Waste to prevent contamination of stormwater, surface water, Groundwater, and soil.

v. If Remediation occurs within High Priority Habitat, the Operator will incorporate Best Management Practices protective of the relevant wildlife species or habitat in the Operator's Form 27.

C. Groundwater that does not meet the cleanup concentrations in Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, will be remediated pursuant to a Form 27.

(6) **Surface Reclamation.** If the Director approves the closure of a Remediation project, the Operator will reclaim the site(s) pursuant to the Commission's 1000 Series Rules.

c. **Form 27, Site Investigation and Remediation Workplan.** Operators will prepare and obtain the Director's approval of a Form 27 prior to conducting the following operations and Remediation activities:

(1) Pit or Cuttings Trench closure;

(2) Buried or partially buried vessel closure, which will be by removal;

(3) Remediation of Spills and Releases pursuant to Rule 912;

(4) Land Treatment of Oily Waste pursuant to Rule 905.e;

(5) Closure of Centralized E&P Waste Management Facilities pursuant to Rule 907.h;

(6) Remediation of impacted Groundwater pursuant to Rule 915.e.(3).D, and the contaminant concentrations in Table 915-1;

(7) Investigation and Remediation of natural gas in soil or Groundwater;

(8) When requested by the Director due to any potential risk to soil, Groundwater, or surface water; and

(9) Decommissioning of Oil and Gas Facilities.

d. **Implementation Schedule.** Each Form 27 will include a specific implementation schedule to complete investigation and Remediation.

(1) Operators will investigate impacts to soil, Groundwater, and surface water as soon as the impacts are discovered.

(2) Any change from the approved implementation schedule will be requested at least 14 days in advance, and the Operator may not make the change without the Director's approval.

e. **Reporting Schedule.** After initial approval of a Form 27, the Operator will provide quarterly update reports in a Supplemental Form 27 to document progress of site investigation and Remediation, unless an alternative reporting schedule has been requested by the Operator and approved by the Director. The Director may request a more frequent reporting schedule based on site-specific conditions.

(1) Operators may not change the reporting schedule without the Director's approval.

(2) By April 15, 2021, Operators of existing remediation projects approved prior to January 15, 2021 will submit a Supplemental Form 27 with a detailed project summary and status.

(3) For existing remediation projects approved prior to January 15, 2021, the Operator will adopt a quarterly reporting schedule unless a more frequent or specific reporting schedule was already approved by the Director.

f. Discovery of a Spill or Release During Closure. If a Spill or Release is discovered during facility closure operations, the Operator will report it to the Director on a Form 19 pursuant to Rule 912.

g. Changes of Operator. Within 60 days of the Director's approval of a Form 9 – Subsequent pursuant to Rule 218.e, the Buying Operator will submit a supplemental Form 27 designating the responsible Operator for all open Remediation projects.

h. Closure.

(1) Remediation will be considered complete when the Operator has demonstrated compliance with:

A. The cleanup concentrations in Table 915-1;

B. WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, if applicable; and

C. Any condition of approval of a Form 27.

(2) An Operator may request a variance pursuant to Rule 502 to comply with an alternative standard in lieu of one or more of the standards in Rules 913.h.(1).A & C. In addition to applying for a variance, the Operator will also submit a Form 27 demonstrating that their alternative clean-up process protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(3) For contaminated groundwater where periodic monitoring has been required, closure may not occur until after 4 consecutive quarters of sampling and analysis demonstrating compliance with Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, if applicable.

(4) **Notification of Completion.** Within 30 days after conclusion of site Remediation activities:

A. Operators conducting Remediation operations pursuant to an approved Form 27 will submit to the Director a Supplemental Form 27 containing documentation sufficient to demonstrate compliance with the Commission's Rules.

B. Operators will coordinate with the Director through a Form 4 regarding additional surface Reclamation required by the Commission's 1000 Series Rules, if applicable.

i. Release of Financial Assurance. Financial Assurance required by Rule 706 may be held by the Director until the required Remediation of soil and/or Groundwater impacts is completed in accordance with the approved workplan, or until cleanup goals are met.

914. CRITERIA TO ESTABLISH POINTS OF COMPLIANCE

In determining a Point of Compliance, the Director will take into consideration recommendations of the Operator or any Responsible Party or Parties, if applicable, together with the following factors:

a. The classified use established by the WQCC, for any Groundwater or surface water that was impacted by contamination. If not so classified, the interim narrative standard applies, and the domestic and agricultural uses are to be protected;

b. The geologic and hydrologic characteristics of the site, such as depth to Groundwater, Groundwater flow, direction and hydraulic conductivity, soil types, surface water impacts, and any seasonal hydrologic variability;

c. The toxicity, mobility, and persistence in the environment of contaminants released or discharged from the site;

d. Established wellhead protection areas;

e. The potential of the site as an Aquifer recharge area;

f. The distance to the nearest permitted domestic water well or Public Water System supply well completed in the same Aquifer affected by the event; and

g. The distance to the nearest permitted livestock or irrigation water well completed in the same Aquifer affected by the event.

915. CONCENTRATIONS AND SAMPLING FOR SOIL AND GROUNDWATER

a. Soil Concentrations. Operators will adhere to the concentrations for soil cleanup in Table 915-1. Operators will use Residential Soil Screening Level Concentrations as cleanup levels unless required otherwise by the Director. The Director will require adherence to the Protection of Groundwater Soil Screening Levels when a pathway to Groundwater exists. When the Director has reasonable cause to believe that oil and gas exploration-related compounds or parameters other than those listed in Table 915-1 may be present, the Director may require additional analyses of compounds included in the EPA RSLs, as incorporated by reference in Rule 901.b.

b. Soil Suitability for Reclamation. Operators will adhere to the concentrations for soil in Table 915-1 for restoring soil to the agronomic properties for electrical conductivity ("EC"), sodium adsorption ratio ("SAR"), pH, and boron for soils. Subject to prior approval by the Director, Operators may leave materials with elevated concentrations of EC, SAR, or pH *in situ*. In such cases, the Operator will provide a detailed Reclamation plan that includes, but is not limited to, soil analysis from adjacent undisturbed lands, revegetation techniques, site stabilization, and details of seeded species.

c. Groundwater Concentrations. Operators will adhere to the concentrations for Groundwater in Table 915-1. The Groundwater standards and analytical methods are derived from the Groundwater standards and classifications established by WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

d. Additional Groundwater Analyses. When the Director has reasonable cause to believe that oil and gas exploration-related compounds or parameters other than those listed in Table 915-1 may be present, the Director may require additional analyses beyond the list of compounds included in Table 915-1 for Groundwater including but not limited to:

(1) Any element, compound or parameter listed in Table A and Tables 1, 2, 3, and 4 of WQCC Regulation 41, as incorporated by reference in Rule 901.b.

(2) In accordance with the Narrative Standards of WQCC Regulation 41.5.A, any element, compound, or parameter not listed in Table A or Tables 1, 2, 3, and 4 of WQCC Regulation

41, as incorporated by reference in Rule 901.b, which alone or in combination with other substances, are in concentrations shown to be:

A. Carcinogenic, mutagenic, teratogenic, or toxic to human beings; or,

B. A danger to public health, safety, and welfare.

e. Sampling and Analysis. Analysis will be conducted using EPA SW-846 analytical methods, as incorporated by reference in Rule 901.b, or, with the Director's approval, other analytical methods published by nationally-recognized organizations. Analyses of samples will be performed by laboratories that maintain state or national accreditation programs. Operators will adhere to the specialized agricultural analytical methods where required pursuant to footnote 2 to Table 915-1. A lab with experience with agricultural analysis will be used.

(1) Methods for Sampling and Analysis. Sampling and analysis for site investigation or confirmation of successful Remediation will be conducted to determine the nature and extent of impact and confirm compliance with appropriate concentration levels in Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

A. Field Analysis. Field measurements and field tests will be conducted using appropriate equipment, calibrated and operated according to manufacturer specifications, by personnel trained and familiar with the equipment. Operators will provide all field measurements and tests to the Director upon request, including but not limited to field notes, field screening logs, soil boring logs, monitor well construction Logs, pump test reports, photographs, and soil vapor screening results.

B. Sample Collection. Samples will be collected, preserved, documented, and shipped or delivered to a laboratory under a chain-of-custody protocol using standard environmental sampling procedures in a manner to ensure accurate representation of site conditions.

C. Laboratory Analytical Methods. Laboratories will analyze samples using standard methods (including but not limited to EPA SW-846, as incorporated by reference in Rule 901.b) appropriate for detecting the target analyte. The method selected will have detection limits less than or equal to the cleanup concentrations in Table 915-1 and WQCC Regulation 41, as incorporated by reference in Rule 901.b.

D. Background Sampling. The Director may require the Operator to take site-specific samples, outside of the area disturbed by Oil and Gas Operations, of comparable, nearby, non-impacted, native soil, Groundwater or other media to establish background conditions.

(2) Soil Sampling and Analysis.

A. Applicability. If soil contamination is suspected or known to exist as a result of Spills or Releases or E&P Waste management, Operators will collect and analyze representative samples of soil pursuant to this Rule 915.e.(2).

B. Sample Collection. Samples will be collected from areas most likely to have been impacted, and the horizontal and vertical extent of contamination will be determined. The number and location of samples will be appropriate to determine the horizontal and vertical extent of the impact.

C. Sample Analysis. Operators will analyze soil samples for contaminants of concern listed in Table 915-1 as appropriate to assess the impact or confirm Remediation. If an

Operator believes it is appropriate to modify the list of contaminants of concern, the Operator will submit, and obtain the Director's approval of, a modified list of contaminants of concern through a Form 19 or Form 27, as applicable. The list will be based on site specific E&P Waste profile and process knowledge. Operators will analyze samples for additional contaminants of concern upon the Director's request.

D. Soil Background Determination. For impacts to soil due to E&P Waste, samples from comparable, nearby non-impacted native soil will be collected and analyzed for purposes of establishing background soil conditions including pH, EC, SAR, and other constituents as identified in the E&P Waste profile.

(3) Groundwater Sampling and Analysis.

A. Applicability. Operators will collect and analyze representative samples of Groundwater if:

i. Groundwater contamination is suspected or is known to exceed the concentrations in cleanup Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b;

ii. Impacted soils are in contact with Groundwater; or

iii. Impacts to soils extend down to the high water table.

B. Sample Collection. Operators will collect samples as soon as possible from areas most likely to have been impacted: immediately downgradient or in the middle of excavated areas in close proximity to the suspected source of the impact.

i. The number and location of samples will be appropriate to determine the horizontal and vertical extent of the impact.

ii. If the cleanup concentrations in Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, are exceeded, the direction of flow and a Groundwater gradient will be established.

iii. The Director may require the installation of temporary or permanent monitoring wells as necessary for sample collection. All monitoring wells will be constructed and permitted in accordance with the State Engineer's Water Well Construction and Permitting Rules, as incorporated by reference in Rule 901.b.

C. Sample Analysis. Operators will analyze Groundwater samples for constituents of concern listed in Table 915-1, or other parameters appropriate for evaluating the impact, to assess the impact or confirm Remediation. If an Operator believes it is appropriate to modify the list of constituents of concern, the Operator will submit, and obtain the Director's approval of, a modified list of constituents of concern through a Form 19 or Form 27, as applicable. The list will be based on site specific E&P Waste profile and process knowledge. Operators will analyze samples for additional constituents of concern upon the Director's request.

D. Impacted Groundwater. Pursuant to Rule 913.c.(6), if Groundwater contaminants exceed the concentrations listed in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, Operators will notify the Director and submit to the Director for prior approval a Form 27 for the investigation, Remediation, or monitoring of

Groundwater to meet the required cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(4) Waste and Produced Fluids Sampling and Analysis. When required by the Director, Operators will collect samples necessary to adequately characterize the composition of produced oil, condensate, water, drilling Fluids, drill cuttings, production gases, Bradenhead gases, soil gas, and soil gas seeps. The Operator will submit, and obtain the Director's approval of the number of samples collected, the analyte lists, and analytical methods appropriate to the waste or production stream.

f. Remediations in Progress. For sites that are subject to an open Form 19 or Form 27 as of January 15, 2021, Operators may seek the Director's permission to comply with the version of Table 910-1 that was previously in effect, if Remediation is completed by January 15, 2022. If Remediation at a site subject to an open Form 19 or Form 27 is not completed by January 15, 2022, then the Operator will comply with the current version of Table 915-1.

Table 915-1
CLEANUP CONCENTRATIONS

Contaminant of Concern	**Concentrations**
Soil TPH (total volatile [C_6-C_{10}] and extractable [C_{10}-C_{36}] hydrocarbons)	500mg/kg
Soils and Groundwater - liquid hydrocarbons including condensate and oil	below visual detection limits
Soil Suitability for Reclamation	
Electrical conductivity (EC) (by saturated paste method)[1,2]	<4mmhos/cm
Sodium adsorption ratio (SAR) (by saturated paste method)[1,2,3]	<6
pH (by saturated paste method)[1,2]	6–8.3
boron (hot water soluble soil extract)[1,2,3]	2mg/l
Organic Compounds in Groundwater[4]	
benzene	5µg/l
toluene[5]	560 to 1,000µg/l
ethylbenzene	700µg/l
xylenes (sum of o-, m- and p- isomers = total xylenes)[5]	1,400 to 10,000µg/l
naphthalene	140µg/l
1,2,4-trimethylbenzene	67µg/l
1,3,5-trimethylbenzene	67µg/l
Groundwater Inorganic Parameters[4]	
total dissolved solids (TDS)[1]	<1.25 X local background
chloride ion[1]	250mg/l or <1.25 X local background
sulfate ion[1]	250mg/l or <1.25 X local background

Table 915-1 (continued)

Contaminant of Concern	Concentrations	
	Residential Soil Screening Level Concentrations (mg/kg)[7]	**Protection of Groundwater Soil Screening Level Concentrations (mg/kg) Risk Based (R) and MCL Based (M)**[7,8]
Organic Compounds in Soils[6, 9, 10]		
benzene	1.2	0.0026 (M)
toluene	490	0.69 (M)
ethylbenzene	5.8	0.78 (M)
xylenes (sum of o-, m- and p- isomers = total xylenes)	58	9.9 (M)
1,2,4-trimethylbenzene	30	0.0081 (R)
1,3,5-trimethylbenzene	27	0.0087 (R)
acenaphthene	360	0.55 (R)
anthracene	1800	5.8 (R)
benz(a)anthracene	1.1	0.011 (R)
benzo(b)fluoranthene	1.1	0.3 (R)
benzo(k)fluoranthene	11	2.9 (R)
benzo(a)pyrene	0.11	0.24 (M)
chrysene	110	9 (R)
dibenzo(a,h)anthracene	0.11	0.096 (R)
fluoranthene	240	8.9 (R)
fluorene	240	0.54 (R)
indeno(1,2,3-cd)pyrene	1.1	0.98 (R)
1-methylnaphthalene	18	0.006 (R)
2-methylnaphthalene	24	0.019 (R)
naphthalene	2	0.0038 (R)
pyrene	180	1.3 (R)
Metals in Soils [1, 6, 9, 10, 11]		
arsenic	0.68	0.29 (M)
barium	15000	82 (M)
cadmium	71	0.38 (M)
chromium (VI)	0.3	0.00067 (R)
copper	3100	46 (M)
lead	400	14 (M)
nickel	1500	26 (R)
selenium	390	0.26 (M)
silver	390	0.8 (R)
zinc	23000	370 (R)

Table 915-1 (continued) footnotes

[1] The Director will consider site-specific background concentrations or reference levels in native soils and Groundwater.

[2] Soil suitability thresholds for electrical conductivity ("EC"), pH, and sodium adsorption ratio ("SAR") in soils are based on use of saturated paste preparation methods, followed by analysis. Soil suitability thresholds for available boron are based on hot water soluble (or DPTA/sorbitol) extraction followed by analysis. Methods for preparation and analysis of the soil suitability parameters can be found in Soil, Plant, and Water Reference Methods for the Western Region, as incorporated by reference in Rule 901.b.

[3] With the Director's prior approval, SAR levels and the concentration for hot water soluble boron may be modified based on land use, depth, or characteristics of the vegetative community.

[4] Concentrations for Groundwater are taken from WQCC Regulation 41, as incorporated by reference in Rule 901.b.

[5] For toluene and xylenes (total), the first number in the range is a strictly health-based value based on the WQCC's established methodology for human health-based standards. The second number in the range is a maximum contaminant level ("MCL"), established under the federal Safe Drinking Water Act which has been determined to be an acceptable level of this Chemical in public water supplies, taking treatability and laboratory detection limits into account. The WQCC intends that control requirements for this Chemical be implemented to attain a level of ambient water quality that is at least equal to the first number in the range except as follows: 1) where Groundwater quality exceeds the first number in the range due to a Release of contaminants that occurred prior to September 14, 2004 (regardless of the date of discovery or subsequent migration of such contaminants), clean-up levels for the entire contaminant plume will be no more restrictive than the second number in the range or the Groundwater quality resulting from such Release, whichever is more protective; and 2) whenever the WQCC has adopted alternative, site-specific standards for the Chemical, the site-specific standards will apply instead of these statewide standards.

[6] Concentrations for organic compounds and metals in soils are taken from the November 2020 EPA Regional Screening Levels ("EPA RSLs") for Chemical Contaminants at Superfund Sites, as incorporated by reference in Rule 901.b.

[7] If there is no pathway for communication with Groundwater, then residential soil screening levels apply for organic compounds and metals. If the Director determines that a pathway to Groundwater exists, then the protection of Groundwater soil screening levels will apply, secondary to actual measured concentrations of the contaminants of concern in Groundwater.

[8] The letter "(R)" following a protection of Groundwater soil screening level indicates the concentration is derived from a risk-based approach. The letter "(M)" following a protection of Groundwater soil screening level indicates the concentration is derived from the drinking water MCL.

[9] If the method detection limit ("MDL") or practical quantitation limit ("PQL") for a pollutant is higher (less stringent) than a threshold concentration listed in Table 915-1, the Director may allow an Operator to substitute the MDL or PQL for the concentration listed in Table 915-1.

[10] The risk based cleanup concentrations for organic compounds in soils shown in Table 915-1 are taken from the EPA RSLs, as incorporated by reference in Rule 901.b, tables for Target Risk ("TR") = $1x10^{-6}$ and Target Hazard Quotient ("THQ")=0.1. The risk-based cleanup concentrations for metals in soils shown in Table 915-1 are taken from the EPA RSLs, as incorporated by reference in Rule 901.b, tables for TR=$1X10^{-6}$ and THQ=1. The EPA RSL Frequently Asked Questions pages suggest that the THQ=0.1 tables are appropriate when more than 1 compound of concern is to be considered as present or likely to be present as is typical in soils impacted with organic compounds in Spills or Releases of produced water or liquid hydrocarbons.

[11] The Director will consider Residential Soil Screening Level Concentrations up to 1.25 times site specific background levels for metals in soil.

APPENDIX B

Statement of Basis, Specific Statutory Authority, and Purpose
New Rules and Amendments to Current Rules of the
Colorado Oil and Gas Conservation Commission, 2 C.C.R. § 404-1

Cause No. 1R Docket No. 200600155
800/900/1200 Mission Change, Cumulative Impacts,
and Alternative Location Analysis Rulemaking

This statement sets forth the basis, specific statutory authority, and purpose for amendments ("800/900/1200 Mission Change Rulemaking") to the Colorado Oil and Gas Conservation Commission ("Commission" or "COGCC") Rules of Practice and Procedure, 2 C.C.R. § 404-1 ("Rules").

Unless otherwise specified, the new rules and amendments become effective on January 15, 2021.

In adopting amendments to the Rules, the Commission relied upon the entire administrative record for this rulemaking proceeding, which formally began on June 19, 2020, when the Commission submitted its Notice of Rulemaking to the Colorado Secretary of State for revisions to its 800, 900, and 1200 Series Rules and related 100 Series definitions. This record includes public comments, written prehearing statements, written prehearing testimony, and oral testimony and comments provided during public hearings and Commission deliberations.

Background

In the 800/900/1200 Mission Change Rulemaking, the Commission revised its Rules to align with the statutory amendments adopted in Senate Bill 19-181. The 800/900/1200 Mission Change Rulemaking fulfills the Commission's statutory obligation to undertake three specific rulemakings: one to implement changes to the agency's mission, one to evaluate and address potential cumulative impacts, and one to adopt an alternative location analysis process. Because each of these topics are fundamentally interrelated, the Commission chose to address all three topics in the same rulemaking process. The 800/900/1200 Mission Change Rulemaking occurred simultaneously with a separate but closely related Mission Change Rulemaking, in which the Commission revised its 200 through 600 Series Rules and related 100 Series definitions.

Additionally, in the 800/900/1200 Mission Change Rulemaking the Commission revised its Rules to comply with several other statutory changes made by Senate Bill 19-181, including provisions relating to the role of local governments, the transition to a full-time Commission, and revisions to several statutory definitions.

Finally, the Commission improved the clarity of its Rules by grouping related Rules together in the same Series and by re-ordering Rules within Series to follow a more logical, sequential order. The Commission also eliminated duplicative, outdated, and unnecessary Rules. And the Commission used clearer language, eliminated typographic errors, and ensured consistency throughout its Rules.

Statutory Authority

A. Mission Change.

On April 16, 2019, Governor Polis signed Senate Bill 19-181 into law. Senate Bill 19-181 changed the Oil and Gas Conservation Act's (the "Act") legislative declaration from directing the Commission to "[f]oster the responsible, balanced development, production, and utilization of the natural resources of oil and gas in the state of Colorado in a manner consistent with protection of public health, safety, and welfare, including protection of environment and wildlife resources," C.R.S. § 34-60-102(1)(a)(I) (2018), to directing the Commission to "[r]egulate the development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources," C.R.S. § 34-60-102(1)(a)(I) (2020). In sum, the General Assembly changed the term "foster" to "regulate;" removed the terms "responsible," "balanced," and "utilization;" and changed the phrase "in a manner consistent with protection of" to "in a manner that protects."

Consistent with these changes to the Act's legislative declaration, Senate Bill 19-181 also added a new mandate that "[i]n exercising the authority granted by this article 60, the Commission shall regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources and shall protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5)(a).

To implement this change in the Commission's mission, the General Assembly required the Commission to undertake a rulemaking to ensure that the Commission's regulations are consistent with the revised legislative declaration and C.R.S. § 34-60-106(2.5)(a). Several subsections of Senate Bill 19-181 reference "rules required to be adopted by section 34-60-106(2.5)(a)." C.R.S. §§ 34-60-104(1)(b), 34-60-104.3(5), 34-60-106(1)(f)(III).

B. Cumulative Impacts.

Senate Bill 19-181 also directed the Commission to adopt rules, in consultation with the Colorado Department of Public Health and Environment ("CDPHE"), to "evaluate and address the potential cumulative impacts of oil and gas development." C.R.S. § 34-60-106(11)(c)(II). Because evaluating and addressing potential cumulative impacts is inextricably tied to many of the Commission's other Rules that were subject to revisions in the 800/900/1200 Mission Change Rulemaking, the Commission chose to revise its Rules to evaluate and address cumulative impacts as part of the 800/900/1200 Mission Change Rulemaking.

C. Alternative Location Analysis.

Senate Bill 19-181 further directed the Commission to "adopt an alternative location analysis process and specify criteria used to identify oil and gas locations and facilities proposed to be located near populated areas that will be subject to the alternative location analysis process." C.R.S. § 34-60-106(11)(c)(I). Like cumulative impacts, the alternative location analysis process is closely related to issues central to the 800/900/1200 Mission Change Rulemaking, including revising the Commission's rules to recognize local government siting authority, and revising the Commission's permitting and location assessment rules to better protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Accordingly, the Commission also chose to adopt an alternative location analysis process as part of the 200–600 Mission Change Rulemaking, and adopt related rules as part of the 800/900/1200 Mission Change Rulemaking.

D. Other Statutory Changes.

Although Senate Bill 19-181 specifically required the Commission to conduct rulemakings to address the agency's new mission, cumulative impacts, and alternative location analysis, Senate Bill 19-181 also revised many other statutory provisions without requiring specific rulemakings to implement those statutory changes. Key statutory changes include the role of local governments, the transition to a full-time Commission, and revising important definitions. Accordingly, the Commission revised its Rules to reflect many of those changes in the 800/900/1200 Mission Change Rulemaking.

1. Local Governments.

Senate Bill 19-181 substantially revised the role local governments play in regulating the siting and surface impacts of oil and gas facilities. Among other things, Senate Bill 19-181 specified that nothing in the Act "alters, impairs, or negates the authority of . . . a local government to regulate oil and gas operations pursuant to section 29-20-104." C.R.S. § 34-60-105(1)(b)(V). Further, Senate Bill 19-181 requires that when applying for permits to drill from the Commission, operators must prove that they have "filed an application with the local government with jurisdiction to approve the siting of the proposed oil and gas location and the location government's disposition of the application; or the local government with jurisdiction does not regulate the siting of oil and gas locations." *Id.* § 34-60-106(1)(f)(I)(A). Senate Bill 19-181 included a similar provision requiring applicants to submit a disposition from the local government with siting jurisdiction (or evidence that the local government with jurisdiction does not regulate oil and gas location siting) when submitting a spacing application. *Id.* § 34-60-116(1)(b)(I)–(II). Finally, Senate Bill 19-181 adds a new section to Article 60 entitled "No land use preemption," which provides that "[l]ocal governments and state agencies, including the commission and agencies listed in section 34-60-105(1)(b), have regulatory authority over oil and gas development, including as specified in section 34-60-105(1)(b). A local government's regulations may be more protective or stricter than state requirements." *Id.* § 34-60-131.

In addition to amending the Act, Senate Bill 19-181 also revised the Local Government Land Use Control Enabling Act by authorizing local governments to "regulat[e] the surface impacts of oil and gas operations in a reasonable manner to address matters specified in this subsection (1)(h) and to protect and minimize adverse impacts to public health, safety, and welfare and the environment." C.R.S. § 29-20-104(1)(h). Among other things, the General Assembly specified that local governments have authority over land use, location and siting of oil and gas facilities, impacts to public facilities and services, water quality, water source, noise, vibration, odor, light, dust, air quality, land disturbance, reclamation, cultural resources, emergency preparedness, security, and traffic issues related to oil and gas development. *Id.* § 29-20-104(1)(h)(I)–(IV).

In the 800/900/1200 Mission Change Rulemaking, the Commission revised several of its Rules to reflect the changes to local government statutory authority and recognize the role that local governments play in approving the siting of oil and gas facilities. The Commission implemented Senate Bill 19-181's framework of co-equal, independent siting authority for both the Commission and local governments, in recognition that operators must obtain siting approval from both the Commission and a local government. The Commission adopted a process that allows each entity with jurisdiction over facility siting—the Commission and local government—to work together on siting decisions in a manner that recognizes their dual authority. Through the framework established in the adopted Rules, the Commission intends to implement this process by facilitating consultation and coordination between the Commission, local governments, operators, and other stakeholders to identify locations that meet the requirements of both permitting regimes, including the protection of public health, safety, welfare, the environment, and wildlife resources. Numerous Rules adopted by the Commission in the 800/900/1200 Mission Change Rulemaking are intended to facilitate the permitting process in recognition of the co-equal authority of local governments, while minimizing unnecessary burdens on operators, who must obtain permits from both the Commission and a local government before conducting new operations.

The revisions to the Commission's Rules in the 800/900/1200 Mission Change Rulemaking specifically implement Senate Bill 19-181's addition of the new section 131 to Article 60 providing that "[a] local government's regulations may be more protective or stricter than state requirements." C.R.S. § 34-60-131. This statutory provision provides that local governments may adopt regulations that are different than the Commission's Rules without those regulations being preempted, even if the local regulations are more protective or stricter than the state standards. Thus, a local government may adopt its own standards to address the same surface impacts, and operators may therefore be required to comply with a more protective local government standard. Nothing in the text of Senate Bill 19-181 expressly prohibits a local government from adopting a less strict or less protective standard that the Commission. However, should such a circumstance arise, an operator would nevertheless be required to also comply with the Commission's more protective standard. This is the nature of co-equal and independent authority: operators must comply with both local and state regulations of surface impacts, regardless of which is more protective.

2. Full-Time Commission.

Another fundamental change enacted by Senate Bill 19-181 is a transition to a Commission staffed by five full-time professionals. Previously, the Commission was a nine-member volunteer body that met periodically. Senate Bill 19-181 made several structural changes to the Commission. C.R.S. § 34-60-104.3(2).

The full-time Commission provisions of Senate Bill 19-181 became effective on July 1, 2020. *See id.* Because the 800/900/1200 Mission Change Rulemaking occurred after the full-time Commission was seated on July 1, 2020, the Commission revised several of its Rules to account for the transition to a full-time Commission.

3. Revised Definitions.

Finally, Senate Bill 19-181 revised several statutory definitions of terms used in the Act. In the 800/900/1200 Mission Change Rulemaking, the Commission has revised several of its Rules to account for these revised definitions.

First, Senate Bill 19-181 revised the definition of "waste." C.R.S. § 34-60-103(11)–(13). The General Assembly added a new clause to the definition specifying that waste "does not include the nonproduction of oil or gas from a formation if necessary to protect public health, safety, and welfare, the environment, or wildlife resources as determined by the Commission." *Id.* § 34-60-103(13)(b); *see also id.* §§ 34-601-103(11)(b), (12)(b). In the 800/900/1200 Mission Change Rulemaking, the Commission revised several of its Rules to account for the revised definition.

Second, Senate Bill 19-181 amended the definition of "minimize adverse impacts," a term used both to describe the Commission's new mission, C.R.S. § 34-60-106(2.5)(a), and the powers of local governments, *id.* § 29-20-104(1)(h). Previously, the definition of "minimize adverse impacts" directed the Commission to avoid adverse impacts only

"wherever reasonably practicable" and "tak[ing] into consideration cost-effectiveness and technical feasibility." *See* C.R.S. § 34-60-103(5.5) (2018). Under the new definition, minimize adverse impacts means "to the extent necessary and reasonable to protect public health, safety, and welfare, the environment, and wildlife resources." C.R.S. § 34-60-103(5.5) (2020). The new definition of "minimize adverse impacts" now specifically excludes considerations of cost-effectiveness and technical feasibility, and replaces "wherever reasonably practicable" with "to the extent necessary and reasonable." In the 800/900/1200 Mission Change Rulemaking, the Commission has revised several of its Rules to match the revised definition.
One of the key operative statutory provisions where the revised definition of "minimize adverse impacts" appears is C.R.S. § 34-60-106(2.5)(a). Prior to Senate Bill 19-181, Section 106 of the Act provided that:

> The commission has the authority to regulate . . . Oil and gas operations so as to prevent and mitigate significant adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations to the extent necessary to protect public health, safety, and welfare, including protection of the environment and wildlife resources, *taking into consideration cost-effectiveness and technical feasibility*.

C.R.S. § 34-60-106(2)(d) (2018) (emphasis added)

As amended by Senate Bill 19-181, Section 106 of the Act provides that:

> In exercising the authority granted by this article 60, the commission shall regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources and shall protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations.

C.R.S. § 34-60-106(2.5)(a) (2020). Thus, in addition to using the defined term "minimize adverse impacts," the revised version of C.R.S. § 34-60-106(2.5)(a) does not include the phrase "cost-effectiveness and technical feasibility."

As discussed above, one of the primary purposes of the 200–600 Mission Change Rulemaking is to implement the changes to the Commission's mission and statutory authority in C.R.S. § 34-60-106(2.5)(a). *See* C.R.S. §§ 34-60-104(1)(b), 34-60-104.3(5), 34-60-106(1)(f)(III) (referencing "rules required to be adopted by section 34-60-106(2.5)(a)"). Accordingly, throughout the 200–600 Mission Change Rules, the Commission added the phrase "protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources." The Commission intends for all references to this phrase to serve as direct references to the entirety of C.R.S. § 34-60-106(2.5)(a). The Commission omitted components of the full statutory language ("regulate oil and gas operations in a reasonable manner to" and "protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations") to make the Commission's Rules more readable and understandable. The omission of each of these clauses does not in any way indicate that the Commission or the Director will not consider all factors listed in C.R.S. § 34-60-106(2.5)(a), including regulating in a "reasonable manner" and protecting "against adverse environmental impacts on any air, water, soil, or biological resource" when making decisions pursuant to the Commission's Rules.

Many stakeholders commented on the role that the Commission's Rules play in protecting biological resources. Senate Bill 19-181 did not substantially change the Commission's authority to protect and minimize adverse impacts to biological resources.

As seen above, consistent with changes to the definition of "minimize adverse impacts," Senate Bill 181 removed consideration of cost-effectiveness and technical feasibility from the operative statutory clause providing the Commission with authority to regulate oil and gas operations in a manner to protect various resources, including biological resources. However, Senate Bill 19-181 did not create a wholesale new mandate for the Commission to adopt regulations requiring the protection of biological resources, or otherwise substantially change the role of protecting biological resources within the broader scheme of the Commission's regulations.

Consistent with the limited scope of the statutory change, in the 200–600 Mission Change Rulemaking, the Commission maintained and strengthened many of its existing Rules that are intended to protect biological resources, but did not make significant changes to its approach to protecting biological resources. For example, both the Commission's prior Rules and Rules adopted in the 200–600 Mission Change Rulemaking require operators to identify wetlands and reference areas for vegetative communities on Form 2A applications. *Compare* prior Rule 303.b.(3).G.ii (reference areas) & S (wetlands) *with* Rule 304.b.(9).B (reference areas) & (14) (wetlands). The Commission clarified and expanded the standards for reference area identification, by requiring operators to submit a table identifying the dominant vegetation within the reference area in Rule 304.b.(9).B.iii, and to take reference area photographs during peak growing season to clearly depict vegetation cover and density in Rule 304.b.(6).B.ii. Moreover, in Rule 606.c, the Commission clarified and expanded upon drilling and production-stage weed control requirements, including by adding new definitions of Undesirable Plant Species and Noxious Weeds in the 100 Series Rules. The Commission's 1200 Series Rules and related provisions in the 300 Series Rules, which were amended in the 800/900/1200 Mission Change Rulemaking, are explicitly intended to protect wildlife, which are a form of biological resources. Additionally, many of the Commission's 1000 Series Reclamation Rules, which were not revised during the 200–600 or 800/900/1200 Mission Change Rulemakings, are explicitly intended to protect biological resources and to restore vegetative communities through interim and final reclamation. *See* Rules 1003 & 1004. Attachment 5 provides a more comprehensive list of Rules intended to protect biological resources.

Recognizing the importance of protecting against adverse environmental impacts to biological resources resulting from oil and gas operations, the Commission instructs its Staff to convene a Biological Resources Working Group to evaluate sources of information about vegetation, including rare plants; topsoil; wildlife and wildlife habitat; non-wildlife threatened and endangered species; ecosystems, habitat heterogeneity, and biodiversity; and invasive species management. The stakeholder working group should include Commission Staff, as well as representatives from interested local governments, operators, and community organizations. The Commission intends for the working group to consider sources of information and available data to assist Staff in identifying how to better integrate considerations of biological resources with the Commission's permit review process. Sources of data may include the Colorado Natural Heritage Program, Colorado Parks & Wildlife's ("CPW") State Wildlife Action Plan ("SWAP"), and federal, state, and local governments. Following a review of these sources of information, the working group will make recommendations to the Commission based on its findings. The Commission directs Staff to coordinate a report back to the Commission based on the results of the Biological Resources Working Group by no later than January 15, 2022.

E. Specific Statutory Authority

In addition to the statutory language quoted above, the Commission's authority to promulgate amendments to the Rules is derived from the following sections of the Act:

- C.R.S. § 25-8-202 (Implementing agencies must protect present and future beneficial uses of groundwater);
- C.R.S. § 34-60-102 (Legislative declaration);
- C.R.S. § 34-60-103 (Definitions);
- C.R.S. § 34-60-104.5 (Duties of the Director);
- C.R.S. § 34-60-105 (Powers and authority of the Commission);
- C.R.S. § 34-60-106 (Specific powers and duties of the Commission);
- C.R.S. § 34-60-107 (Prohibiting waste);
- C.R.S. § 34-60-108 (Procedural rules);

- C.R.S. § 34-60-110 (Subpoena power);
- C.R.S. § 34-60-116 (Pooling);
- C.R.S. § 34-60-117 (Protection of correlative rights);
- C.R.S. § 34-60-118 (Unit operations);
- C.R.S. § 34-60-120 (Authority over federal lands and minerals);
- C.R.S. § 34-60-121 (Enforcement);
- C.R.S. § 34-60-122 (Calculation of expenses);
- C.R.S. § 34-60-124 (Oil and gas conservation and environmental response fund);
- C.R.S. § 34-60-127 (Reasonable accommodation of surface owners);
- C.R.S. § 34-60-128 (Habitat stewardship and consultation with Colorado Parks and Wildlife);
- C.R.S. § 34-60-130 (Spill reporting); and
- C.R.S. § 34-60-131 (Local government preemption).

Stakeholder and Public Participation

The 800/900/1200 Mission Change Rules are the product of a robust stakeholder process. Shortly after the passage of Senate Bill 19-181, during the summer of 2019, Commission Staff began regularly meeting with stakeholders and accepting public comments about the Mission Change, Cumulative Impacts, and Alternative Location Analysis Rulemakings. Based on this stakeholder input and Staff's collective decades of experience with administering the prior Rules, on November 1, 2019, the Commission published a Mission Change Whitepaper, providing an outline and discussion of some, but not all, of the larger concept Rule changes under consideration. After publication of the Whitepaper, Commission Staff continued meeting with stakeholders to receive feedback on Staff's proposed conceptual Rule changes.

Based on this feedback, on February 7, 2020, Commission Staff released a "straw dog" draft of revisions to its 800 and 900 Series Rules, among others, to the public. On February 24, 2020, Commission Staff released a "straw dog" draft of revisions to additional parts of the 900 Series Rules to the public. On May 1, 2020, Commission

Staff released revised "straw dog" drafts of revisions to its 800, 900, and 1200 Series Rules that were updated based on stakeholder feedback on the initial "straw dog" drafts. The Commission's Staff solicited specific input from all interested stakeholders and members of the public on the May 1 "Straw Dog" drafts, and incorporated that input into the draft 800, 900, and 1200 Series Rules submitted to the Secretary of State for notice on June 19, 2020.

Additionally, because much of the 800/900/1200 Mission Change Rulemaking involves areas where the Commission regulates activities in close coordination with other state agencies, Commission Staff met with staff from Colorado Parks and Wildlife ("CPW"), the Air Pollution Control Division ("APCD"), the Water Quality Control Division ("WQCD"), and the Hazardous Materials and Waste Management Division ("HMWMD"). Staff from each of these agencies provided valuable input that helped shape the Commission's Rules to avoid inconsistencies and duplication with areas regulated by other state agencies. The Commission's Staff also met with staff from federal regulatory agencies including the Bureau of Land Management ("BLM") and the Environmental Protection Agency ("EPA").

On June 19, 2020, the Commission issued a draft of the proposed 800, 900, and 1200 Series Rules and a Draft Statement of Basis and Purpose with its Notice of Rulemaking. The Commission Noticed the 800/900/1200 Mission Change Rulemaking to occur between August 24 and September 10, 2020.

On June 23, 2020, 95 parties filed applications for party status. On June 26, 2020, the Hearing Office issued a Case Management Order, establishing filing deadlines. On June 29, 2020, the Commission conducted a preliminary stakeholder meeting about the 800/900/1200 Mission Change Rulemaking. On June 30, 2020, the Hearing Office conducted a prehearing conference.

The Hearing Officer's June 26, 2020 Case Management Order also notified the parties that a related petition for rulemaking had been filed by Our Children's Trust, and would be considered and acted upon by the Commission in both the 200–600 and 800/900/1200 Mission Change Rulemakings, as required by the Administrative Procedure Act. C.R.S. § 24-4-103(7). On July 1, 2020, the Hearing Officer issued an Amended Case Management Order, extending the deadline for parties to file responses to the rulemaking petition, allowing parties to file a single consolidated response in both the 200–600 and 800/900/1200 Mission Change Rulemakings dockets, and increasing the page limit for such responses to 15 total pages.

On July 6, 2020 the Hearing Officer issued an Order responding to a motion and response from certain parties. The Order rescheduled the hearing dates for the 800/900/1200 Mission Change Rulemaking to September 28 through October 9, 2020, and adjusted the filing deadlines for written statements accordingly.

Parties filed their consolidated responses to the Our Children's Trust petition on August 7, 2020.

Parties filed prehearing statements for the 800, 900, and 1200 Series on August 19, 2020.

On September 10, 2020, the final date originally noticed for the 800/900/1200 Mission Change Rulemaking hearing, the Commission continued the rulemaking to instead begin on September 28, 2020. The Commission adjusted the schedule to provide additional time for Staff to propose revisions to the 200–600 Mission Change Rules, for parties to provide input on those revisions, and for the Commission to deliberate about the 200–600 Mission Change Rulemaking. On September 10 and 11, the Hearing Officer issued a Second and Third Amended Case Management Order, respectively, reflecting these changes to the schedule for the 800/900/1200 Series Rulemaking Schedule and associated filing dates for prehearing statements, responses, and pre-filed written testimony for the 800, 900, and 1200 Series.

Parties filed responses to prehearing statements in the 800 Series on September 14, 2020.

On September 18, 2020, the Commission's Staff timely submitted a Cost-Benefit Analysis and Regulatory Analysis for the 800/900/1200 Mission Change Rulemaking to the Department of Regulatory Affairs, released the Cost-Benefit Analysis and Regulatory Analysis to the parties, and posted the Cost-Benefit Analysis and Regulatory Analysis on the Commission's website. The Commission was required to prepare the Cost-Benefit Analysis and Regulatory Analysis because American Petroleum Institute Colorado ("API") timely requested a cost-benefit analysis for the 900 Series Rules pursuant to C.R.S. § 24-4-103(2.5)(a), and West Slope Colorado Oil and Gas Association ("WSCOGA") timely requested a cost-benefit analysis and regulatory analysis for the 1200 series rules pursuant to C.R.S. § 24-4-103(4.5)(a).[1] In addition to engagement with stakeholders and review of parties' written filings, the process of preparing the Cost-Benefit Analysis and Regulatory Analysis allowed the Commission's Staff to more comprehensively examine and consider the costs and benefits of many Rules amended in the 800/900/1200 Mission Change Rulemaking, and this analysis informed some of the revisions that the Commission's Staff proposed to certain Rules.

Parties filed written testimony from witnesses on the 800 Series on September 21, 2020.

On September 22, 2020, the Hearing Officer issued a Fourth Amended Case

[1] Staff did not conduct a cost-benefit analysis or regulatory analysis of the 800 Series because no party requested such an analysis.

Management Order, adjusting the dates of the 800/900/1200 Mission Change Rulemaking hearing based on the Commission's direction at its September 18, 2020 hearing about Staff's proposed revisions to the 200–600 Series Rules. The adjusted dates allowed parties time to provide written and oral feedback on Staff's proposed revisions. The revised schedule set the 800 Series hearing for October 6–9, the 1200 Series hearing for October 13–23, and the 900 Series hearing for October 26 through November 6, 2020.

On September 25, 2020, the Commission's Staff released a revised draft of the proposed 800 Series Rules, and a redline comparison against the June 19, 2020 proposed Rules. These revised drafts responded to feedback that parties provided in their prehearing statements, responses, and pre-filed written testimony. The same day, the Commission's Staff released a revised draft of the portions of this Statement of Basis and Purpose addressing the 800 Series, reflecting the revised September 25, 2020 draft 800 Series Rules, and addressing issues raised in party prehearing statements and responses.

Also on September 25, 2020, parties filed responses to prehearing statements in the 1200 Series.

Parties filed written testimony from witnesses on the 1200 Series on October 2, 2020.

The Commission conducted the 800 Series hearing from October 6 through 9, 2020. A member of the public provided oral public comment on October 6. The Commission's Staff, staff from CDPHE's WQCD and APCD, and parties gave opening presentations on October 6. On October 7, some parties gave opening presentations, and Staff and parties that reserved time for closing gave closing presentations. The Commission deliberated and instructed Staff to revise the 800 Series Rules and this Statement of Basis and Purpose based on those deliberations. Staff presented the revisions on October 8. On October 9, parties provided responses to Staff's revised 800 Series Rules, and the Commission finished its deliberations on the 800 Series. On October 9, 2020, the Commission voted unanimously to give preliminarily final approval to the 800 Series Rules, as well as conforming edits to the 100 Series, subject to any conforming edits and the correction of proofreading errors. The same day, the Commission also closed the record for the 800 Series Rules.

Also on October 9, 2020, parties filed responses to prehearing statements in the 900 Series.

Finally, on October 9, 2020, the Commission's Staff released a revised draft of the proposed 1200 Series Rules, and a redline comparison against the June 19, 2020 proposed Rules. These revised drafts responded to feedback that parties provided in their prehearing statements, responses, and pre-filed written testimony. The same day, the Commission's Staff released a revised draft of the portions of this Statement of Basis and Purpose addressing the 1200 Series, reflecting the October 9, 2020 draft 1200 Series Rules, and addressing issues raised in party prehearing statements and responses. The Commission's Staff also updated and released new attachments to the 1200 Series Statement of Basis and Purpose, including Attachment 1 addressing frequently asked questions, Attachment 3, listing literature cited, Attachment 4, summarizing research reviewed by the Commission's Staff and CPW in developing the proposed 1200 Series Rules, and Attachment 5, listing Commission Rules intended to protect to various categories of biological resources.

On October 12, 2020, several parties jointly moved to continue the 1200 Series Rulemaking hearing to provide additional time to respond to Staff's October 9, 2020 draft 1200 Series Rules and Statement of Basis and Purpose. Other parties jointly responded to the motion on October 13, 2020. The Hearing Officer issued a recommended order addressing the motion and response. That same day, the Commission commenced the 1200 Series Rulemaking and adopted the recommended order. The Commission continued the 1200 Series Rulemaking to November 10 through 20, 2020. The Commission directed its Staff to ensure that all materials cited in Attachments 3 and 4 of this Statement of Basis and Purpose were available for public review on the Commission's website. And the Commission authorized parties to file written responses to Staff's October 9, 2020 draft 1200 Series Rules and draft Statement of Basis and Purpose by November 4, 2020.

On October 14, 2020, the Commission's Staff released a revised draft of the proposed 900 Series Rules, and a redline comparison against the June 19, 2020 proposed Rules. These revised drafts responded to feedback that parties provided in their prehearing statements and responses. The same day, the Commission's Staff released a revised draft of the portions of this Statement of Basis and Purpose addressing the 900 Series, reflecting the revised October 14, 2020 draft 900 Series Rules, and addressing issues raised in party prehearing statements and responses.

Parties filed written testimony from witnesses on the 900 Series on October 16, 2020.

The Commission conducted the 900 Series hearing from October 26 through November 5, 2020. The Commission's Staff and gave an opening presentation on October 26. Members of the public provided oral public comment on October 26, 2020. On October 27 and 28, parties gave opening presentations. On October 28, Staff and parties that reserved time for closing gave closing presentations. On October 29, the Commission deliberated and instructed Staff to revise the 900 Series Rules and this Statement of Basis and Purpose based on those deliberations. Staff presented the revisions on November 3. On November 5, parties provided responses to Staff's revised 900 Series Rules, and the Commission finished its deliberations on the 900 Series. On November 5, 2020, the Commission voted unanimously to give preliminarily final approval to the 900 Series Rules, as well as conforming edits to the 100 Series, subject to any conforming edits and the correction of proofreading errors. The same day, the Commission also closed the record for the 900 Series Rules.

Parties filed responses to Staff's October 9, 2020 draft proposed 1200 Series Rules and Statement of Basis and Purpose on November 4, 2020.

The Commission conducted the 1200 Series hearing from November 10 through 20, 2020. Members of the public provided oral public comment on November 10. The Commission's Staff and gave an opening presentation on November 12. On November 12 and 13, parties gave opening presentations. On November 16, Staff and parties that reserved time for closing gave closing presentations. Also on November 16, the Commission deliberated and instructed Staff to revise the 1200 Series Rules and this Statement of Basis and Purpose based on those deliberations. Staff presented the revisions on November 18 and responded to the Commissioners' questions. On November 19, parties provided responses to Staff's revised 1200 Series Rules. The Commission finished its deliberations on the 1200 Series on November 20 and gave final direction to Staff. On November 23, the Commission unanimously voted to approve the 1200 Series Rules, as well as conforming edits to the 100, 300, and 500 Series, subject to any conforming edits and the correction of proofreading errors. The same day, the Commission voted to close the record for the 1200 Series Rules.

In the June 19, 2020 Notice of Rulemaking, the Commission invited stakeholders to participate formally as parties or informally by submitting oral or written comments. The Commission also created online portals through which anyone could submit written comments regarding the 800/900/1200 Mission Change Rulemaking. And the Commission's Staff continued to meet with stakeholders throughout the duration of the Mission Change Rulemaking process, beginning prior to the release of the Mission Change Whitepaper, continuing through the commencement of the rulemaking hearing. Members of the public filed written public comments about the 800 Series pursuant to prior Rule 510 by September 24, 2020. Members of the public filed written public comments about the 900 Series pursuant to prior Rule 510 by October 20, 2020. Members of the public filed written public comments about the 1200 Series pursuant to prior Rule 510 by November 4, 2020. In total, 857 members of the public provided written comments about the 800/900/1200 Mission Change Rulemaking. And 76 members of the public provided oral comments during the Commission's 800, 900 and 1200 Series Rulemaking Hearings, for a total of 5 hours and 27 minutes of public comment.

On November 23, 2020, the Commission unanimously voted to approve the 800, 900, and 1200 Series Mission Change Rules and this Statement of Basis and Purpose.

Identification of New and Amended Rules

Consistent with its statutory authority and its legislative mandates, and in accord with the administrative record, the Commission has revised, reorganized, and added to the regulations in its 800, 900, and 1200 Series Rules. Additionally, the Commission has revised several definitions in its 100 Series Rules, added several new definitions to its 100 Series Rules, removed several definitions from its 100 Series Rules, and made conforming edits to its 300 and 500 Series Rules.

To assist stakeholders in identifying which Rules have been amended, moved, and removed, and which Rules are new, a table cross-referencing the Commission's prior and newly adopted regulations is attached as Attachment 2 to this Statement of Basis and Purpose.

Amendments and Additions to Rules

Throughout the 800/900/1200 Mission Change Rules, the Commission made minor edits, conforming changes, and clarifications to improve clarity and consistency. Among other things, these changes include:

- Phrasing regulatory language in active voice, rather than passive voice, to clarify the responsible entity;

- Capitalizing all terms defined in the 100 Series to signal to stakeholders that the term has a definition;

- Reorganizing Rules between and within Series to ensure that all Rules addressing the same topic are located in the same Series, and making each Series proceed in a logical, sequential order that reflects the order of the practices the Series regulates;

- Eliminating outdated and unnecessary Rules and provisions of Rules that reflect practices or requirements that are no longer in use;

- Eliminating Rules and provisions of Rules that unnecessarily duplicate other Rules;

- Ensuring that the Rules comply with the incorporation by reference provision of the Administrative Procedure Act, C.R.S. § 24-4-103(12.5);

- Streamlining internal cross-references within the Rules;

- Consistently using the term "will" instead of "shall" or "must";

- Using consistent terminology to refer to key entities such as the Commission, the Director, operators, other agencies, and local governments;

- Using consistent terminology to refer to the Commission's Forms;

- Using consistent formatting conventions throughout the Rules; and
- Correcting typographic errors.

Retroactivity

The Commission intends for its revised Rules to be prospective—applying to new operations after January 15, 2021—unless otherwise specified in the text of a Rule or this Statement of Basis and Purpose. The Commission specifically identified which Rules apply retroactively, and therefore would require retrofitting existing facilities, in a limited number of instances. However, Rules that involve ongoing activities or operations that occur at an existing facility after January 15, 2021, rather than specifying construction or equipment standards, are, in fact, intended to apply to existing facilities. Finally, when an existing oil and gas facility is significantly changed or modified, then the Commission's new Rules apply, which may require an operator to retrofit existing equipment.

Applicability to Pending Permit Applications

Pursuant to C.R.S. § 24-4-104.5(2)(a), the Commission intends for all Rules it adopted and amended in the 800/900/1200 Mission Change Rulemaking to apply to all permit applications that were submitted and deemed complete, but not yet approved or denied as of January 15, 2021, the effective date of the Rules. This is consistent with the General Assembly's intent, as expressed in Section 19 of Senate Bill 19-181, which states that "[t]his act applies to conduct occurring on or after the effective date of this act, including determinations of applications pending on the effective date."

The Commission intends for its Staff to issue guidance detailing the procedures that operators with in-process, on-hold, or delayed permit applications may follow to replace their permit applications as necessary to comply with all Rules adopted and amended in the 800/900/1200 Mission Change Rulemaking. The Commission intends for operators to notify Staff by March 1, 2021 about which pending permit applications they intend to replace to comply with the newly-adopted and amended Rules. Operators will have 6 months from the effective date of the 800/900/1200 Mission Change Rules to submit new Form 2As and Form 2s for any in-process, on-hold, or delayed permit application.

The Commission made the following findings to support its determination that all Rules it adopted and amended in the 800/900/1200 Mission Change Rulemaking apply to all pending permit applications:

First, the 800/900/1200 Mission Change Rules materially affect the health and safety of the public. C.R.S. § 24-4-104.5(2)(a)(I)(A). The purpose of the 800/900/1200 Mission Change Rulemaking is to implement Senate Bill 19-181's changes to the

Commission's mission and statutory authority. Senate Bill 19-181 changed the Commission's mission to "[r]egulate the development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources." C.R.S. § 34-60-102(1)(a)(I). Senate Bill 19-181 also instructed that "[i]n exercising the authority granted by this article 60, the Commission shall regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources and shall protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5)(a). Thus, the entire purpose of the 800/900/1200 Mission Change Rulemaking is to adopt Rules that materially affect—and protect—public health and safety. Numerous specific Rules adopted by the Commission in the 800/900/1200 Mission Change Rulemaking are explicitly focused on public health and safety. The list below is not exclusive, and numerous Rules beyond those listed below are intended to protect public health and safety.

- **General Enforcement of Pollution Standards.** Rules 901.a and 902 protect public health by providing the Director and Commission with tools to address imminent risks to public health and to initiate enforcement action to mitigation pollution that poses risks to public health.

- **Reducing Air Pollution.** Rule 903 protects public health by reducing the volume of natural gas that is wasted through venting and flaring, and limiting emissions from pits. Venting natural gas and pit emissions release air pollution that impacts public health, including hazardous air pollutants that have direct health impacts, volatile organic compounds that contribute to tropospheric ozone formation, and methane that contributes to climate change. Flaring natural gas also releases air pollution that impacts public health, including particulate matter that has direct health impacts, nitrogen oxides that contribute to tropospheric ozone formation, and carbon dioxide that contributes to climate change.

- **Preventing & Remediating Surface Water Pollution.** Rules 905.c.(2).D, 905.e.(2).E, 907.b.(5).E, 907.b.(10), 910, 912.a.(4), 912.b.(1), 912.b.(9), 913.b.(5).B and 914.a–b protect public health by ensuring that exploration and production waste management does not contaminate or adversely impact surface water that could be used for drinking water, and requires prompt and thorough cleanup of any impacts to surface water in the event of a spill or release.

- **Preventing & Remediating Groundwater Pollution.** Rules 801.b–c, 802.b.(2)–(3), 803.g.(5).C, 806, 905.a, 905.c.(2).B, 905.e.(2).E.ii, 907.b.(9).B.i, 907.c.(2), 909.j, 912.a.(4), 912.c.(1), 913.b.(2), 913.b.(5), 913.h.(1).B, 914.a, and 915.c–d protect public health by ensuring that groundwater meets Water

Quality Control Commission classifications for drinking water and agricultural water uses, during all forms of exploration & production waste management and when remediating groundwater after a spill or release or other contamination occurs.

- **Preventing the Spread of West Nile Virus.** Rule 1202.a.(9) creates statewide requirements to treat pits to prevent the spread of West Nile virus, which has adverse health impacts for both humans and wildlife.

Second, the continued application of the Commission's Rules that were in effect as of the date permit applications were submitted could potentially result in critical safety measures not being applied to the oil and gas location if the permit applicant does not comply with the Rules adopted and amended in the 800/900/1200 Mission Change Rulemaking. *See* C.R.S. § 24-4-105.5(2)(a)(I)(B). The following Rules are explicitly intended to prevent unsafe situations that could otherwise arise, and to provide better procedures for preventing accidents that otherwise could pose safety risks. The list below is not exclusive.

- **Preventing Induced Seismicity.** Rules 801.d, 803.f.(1), 803.g.(6), and 810.b prevent induced seismicity, which could otherwise create safety risks, by prohibiting injection in proximity to the Precambrian basement, limiting injection volumes to reduce induced seismicity risks, and requiring seismicity evaluations as a component of injection well permitting.

- **Reducing Safety Risks Associated with Venting and Flaring.** Rules 903.a, 903.b.(2), 903.b.(3), 903.c.(3).C, 903.d.(2).B, 903.d.(5), and 903.e.(1).B.iv protect public safety during venting and flaring by requiring notice of flaring to local emergency response agencies, ensuring that flares are enclosed, natural gas that is vented is analyzed for hydrogen sulfide content, and that limited instances of venting and flaring are allowed during drilling and completion to protect safety.

- **Excluding Public Access to Potentially Unsafe Locations.** Rules 909.f, 909.g.(4), and 913.b.(5).B.i require fencing and covering of pits and open excavation sites to prevent unauthorized access by members of the public.

- **Spill and Release Reporting.** Rule 912 updates comprehensive standards for the reporting of spills and releases to protect public safety and ensure that all local and state response agencies are timely notified of spills and releases to protect public safety.

Third, compliance with the adopted and amended 800/900/1200 Mission Change Rules is necessary to ensure that the Commission and all permits it issues will be in compliance with the requirements of federal law and regulations. *See* C.R.S. § 24-4-105.5(2)(a)(II). Several Rules adopted in the 800/900/1200 Mission Change

Rulemaking are intended to ensure compliance with federal laws and regulations. The list below is not exclusive, and Rules beyond those identified here are also intended to ensure compliance with federal laws and regulations.

- **Compliance with the Safe Drinking Water Act & EPA Class II UIC Well Regulations.** The entire 800 Series has been updated to ensure compliance with the latest version of EPA's Safe Drinking Water Act implementing regulations, as required for the Commission to continue exercising its delegated authority from EPA over Class II Underground Injection Control Wells.

- **Compliance with Federal Waste Management Rules.** Rules 902.c, 906.a, and 911.c.(3).A ensure compliance with federal laws governing management of both exploration and production waste and non-E&P waste.

- **Compliance with Federal Radioactive Waste Laws.** Rules 901.b.(3).J and 905.b.(2) ensure compliance with the Rocky Mountain Low-level Radioactive Waste Board's regulations governing interstate transport of radioactive waste.

- **Compliance Federal Spill Reporting Laws.** Rule 912.b.(11) ensures compliance with federal laws governing the reporting of spills and releases, including the Emergency Planning and Community Right to Know Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Oil Pollution Act, and the Clean Water Act.

- **Compliance with the Federal Endangered Species Act.** Rule 309.e.(2).B requires consultation with Colorado Parks and Wildlife for any proposed new oil and gas location or associated infrastructure within federally-designated critical habitat for a threatened or endangered species.

- **Compliance with Federal Land Management Regulations and Plans.** Rules 309.e.(1).F and 309.e.(4).B ensure consideration of federal land use plans in the wildlife consultation process and coordination with appropriate federal agencies.

Finally, compliance with the adopted and amended 800/900/1200 Mission Change Rules is necessary to ensure that the Commission and all permits it issues will not be in conflict with state statutes. *See* C.R.S. § 24-4-105.5(2)(a)(III). The 800/900/1200 Mission Change Rulemaking was conducted to specifically implement three rulemakings required by Senate Bill 19-181: the Mission Change, § 34-60-106(2.5)(a), cumulative impacts, C.R.S. § 34-60-106(11)(c)(II), and alternative location analysis rulemakings, C.R.S. § 34-60-106(11)(c)(I). Additionally, numerous Rules adopted in the 800/900/1200 Mission Change Rulemaking implement other specific statutory changes made by Senate Bill 19-181. Finally, numerous Rules adopted in the 800/900/1200 Mission Change Rulemaking are intended to facilitate compliance with regulations of other state agencies. The list below is not exclusive, and compliance with Rules beyond those identified here is necessary to avoid potential conflicts with Senate Bill 19-181.

- **Local Governments.** Rules 309.e.(4).B, 802.c, 803.g.(14).A, 903.a, 905.a.(4) 905.b.(1), 905.d.(3).b.iii, 907.b.(5).F, 912.b.(7), and 1202.a.(7) implement Senate Bill 19-181's changes to the role local governments play in regulating the siting and surface impacts of oil and gas facilities, and the changes in the relationship between local governments and the Commission. C.R.S. §§ 29-20-104(1)(h), 30-15-401(1)(m), 34-60-105(1)(b)(V), 34-60-106(1)(f)(I)(A), 34-60-106(15), 34-60-116(1)(b)(I)–(II), & 34-60-131.

- **Full-Time Commission.** Rules 802.d, 804.b, 901.a, 904.c, and the 100 Series Definition of High Priority Habitat implement Senate Bill 19-181's transition from a volunteer to full-time Commission by revising practices and procedures to accommodate the full-time Commission. C.R.S. §§ 34-60-104(2), 34-60-104.3, 34-60-104.5(2)(d).

- **Alternative Location Analysis.** Rule 304.b.(2).B.viii implements Senate Bill 19-181's requirement for the Commission to adopt an alternative location analysis process. C.R.S. § 34-60-106(11)(c)(I).

- **Cumulative Impacts.** Rule 904 implements Senate Bill 19-181's requirement for the Commission to adopt regulations to evaluate and address the potential cumulative impacts of oil and gas development. C.R.S. § 34-60-106(11)(c)(II).

- **Compensatory Mitigation.** Rule 1203 implements Senate Bill 19-181's provision exempting off-site compensatory mitigation requirements from the surface owner consent otherwise required for wildlife protection. C.R.S. § 34-60-128(3)(b).

- **Air Quality Control Commission Regulations.** Rules 901.b.(3).D and 903 align the Commission's Rules governing venting and flaring of natural gas and pit emissions with applicable Air Quality Control Commission Regulations.

- **Board of Health Regulations.** Rules 803.g.(5).C–D, 803.h.(1), 806.c, and 909.j align the Commission's Rules governing testing of produced water for specific analytes to match analytes that must be analyzed pursuant to the Board of Health's newly-adopted regulations for Technologically Enhanced Naturally Occurring Radioactive Materials ("TENORM").

- **Colorado Parks and Wildlife.** Rules 304.b.(2).B.viii, 309.e, 529.d.(1), and the entire 1200 Series align the Commission's Rules governing wildlife protection with Colorado Parks and Wildlife regulations and practices to protect wildlife resources.

- **Solid and Hazardous Waste Commission Regulations.** Rules 901.b.(3).B–C, 902.f, 905.d.(2).B, 905.e.(1).B, 905.f.(1), 905.g.(2).A, 906.a–c, 911.c.(3).A, 915.a, and Table 915-1 align the Commission's Rules governing solid and hazardous waste management and soil remediation with the Solid and Hazardous Waste Commission's regulations and the current practices of the Hazardous Materials and Waste Management Division.

- **Water Quality Control Commission Regulations.** Rules 801.b–c, 802.b.(2)–(3), 905.a, 905.c.(2), 905.e.(2), 907.b.(5), (9), & (10), 907.c.(2), 909.j, 910, 912.a.(4), 912.b.(1) (9), 912.c.(1), 913.b, 914.a–b, 915.c–d, and Table 915-1 align the Commission's Rules governing exploration and production waste management and spill and release prevention and remediation with Water Quality Control Commission standards and classifications for groundwater and substantive protections for discharge into surface waters.

<u>100 Series Rules—Definitions</u>

The Commission revised existing 100 Series definitions, removed existing 100 Series definitions, or adopted new 100 definitions of the terms listed below. The purpose of adopting, amending, or eliminating each definition is discussed below alongside the specific Rules in which the definitions apply.

Avoid Adverse Impacts

Centralized E&P Waste Management Facility

Class II UIC Well

Commencement of Production Operations

Commercial Disposal Well

Compensatory Mitigation Plan

Completed Well

Cuttings Trench

Dedicated Injection Well

Flaring

Flowback

Fluid

High Priority Habitat

Injection Zone

Investigation-Derived Waste

Land Application

Land Treatment

Minimize Adverse Impacts

Mitigate Adverse Impacts

Mitigation

Multi-Well Pits

Oily Waste

Pollution

Production Evaluation

Productivity Test

Remediation

Restricted Surface Occupancy Area

Sensitive Wildlife Habitat

UIC Aquifer

Unavoidable Adverse Impacts

Underground Source of Drinking Water

Upset Condition

Venting

Wildlife Mitigation Plan

Wildlife Protection Plan

Wildlife Resources

800 Series
Underground Injection for Disposal and Enhanced Recovery Projects

To improve clarity for operators, local governments, and the public, the Commission consolidated all of its Rules related to injection wells into its 800 Series Rules. Under the Commission's prior Rules, provisions related to injection wells were located in parts of the 300 and 400 Series Rules.

Throughout the 800 Series Rules, and in this Statement of Basis and Purpose, the Commission used the term "injection well" to refer to all Class II Underground Injection Control ("UIC") wells, including both disposal and enhanced recovery wells. When the Commission intended to refer only to wells that are intended to be used for the disposal of Class II fluids, the Commission used the term "disposal well." When the Commission intended to refer only to wells that inject fluids into producing formations to stimulate hydrocarbon production as part of enhanced recovery projects, the Commission used the term "enhanced recovery wells."

Because the Commission made numerous changes to the underground injection program in the 800 Series Rules, the Commission instructs its Staff to issue and update guidance addressing the injection well permitting process, including the timeline for submission and processing Form 31, Underground Injection Formation Permit Applications and Form 33, Injection Well Permit Applications relative to the submission of processing of related 300 Series permit applications, including oil and gas development plans, Form 2A, Oil and Gas Location Assessments, and Form 2, Applications for Permits to Drill.

Rule 801.

The Commission moved prior Rule 324A.d to Rule 801. Prior Rule 324A.d had both a definitional and a substantive component. In Rule 801, the Commission maintained the substantive component, which prohibits injecting any foreign substance into an underground source of drinking water.

The Commission moved the definitional component, which defines an Underground Source of Drinking Water, to the 100 Series. The Commission made minor changes to the wording of the definition for clarity by capitalizing terms that are defined in the Commission's 100 Series Rules, but did not change its substance. The definition is the same as the U.S. Environmental Protection Agency's ("EPA") definition. 40 C.F.R. § 144.3. Some stakeholders suggested changing the definition of Underground Source of Drinking Water to not use the term "public water system," because the Commission's 100 Series Rules define public water systems as conveyances that provide water to either 15 service connections or at least 25 individuals for most of the year. The Commission did not adopt these stakeholders' suggestion, because of the importance of matching EPA's definition of this term that is central to the

Commission exercising its delegated authority to implement EPA's National Primary Drinking Water Regulations for Class II UIC wells. However, as discussed below, the Commission amended Rule 802.b.(1) to provide that UIC aquifer exemptions will not be granted for aquifers that either meet the definition of Underground Source of Drinking Water or are currently serving as a domestic water source. Thus, the Commission would not grant a UIC aquifer exemption for an aquifer that currently serves as a source of drinking water for a domestic water well, even if that aquifer did not meet the definition of an Underground Source of Drinking Water.

<u>*Rule 801.a*</u>

The Commission changed the substantive component, which remains in Rule 801.a, in two ways. First, consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, *see* C.R.S. § 34-60-106(2.5)(a), the Commission added "adversely affect[ing] the health of person" to the list of reasons that a proposed injection well will not be authorized. Second, the Commission updated the cross-reference to the EPA's National Primary Drinking Water Regulations, 40 C.F.R. Part 141, to reference the current version of EPA's standards. The updated cross-reference also complies with the Colorado Administrative Procedure Act's requirements for incorporations by reference. *See* C.R.S. § 24-4-103(12.5).

Incorporating EPA's National Primary Drinking Water Regulations by reference in Rule 801 underscores one of the Commission's fundamental purposes in adopting its 800 Series Rules: to exercise its delegated authority under the federal Safe Drinking Water Act ("SDWA"). To protect drinking water aquifers, SDWA divides underground injections into several different categories, known as "classes." 40 C.F.R. § 144.6. Class II UIC wells are used to inject fluids brought to the surface during oil and gas production and for secondary or tertiary recovery of oil and gas. *See* 42 U.S.C. § 300h-4(a)(1)–(2); 40 C.F.R. § 144.6(b). Section 1425 of SDWA allows EPA to delegate primary authority over Class II UIC wells to state agencies that have adopted regulations meeting all of SDWA's statutory standards and EPA's regulatory standards. 42 U.S.C. § 300h-4(a), (c)(2). EPA delegated primary enforcement authority over all Class II UIC Wells in Colorado to the Commission in 1984. 49 Fed. Reg. 13,040, 13,040–41 (Apr. 2, 1984); *see also* 40 C.F.R. § 147.300.[2]

Because the Commission's 800 Series Rules are an exercise of delegated authority, the Commission has a continuing duty to comply with EPA's SDWA regulations for UIC wells whenever EPA updates those standards. *See* 42 U.S.C. § 300h-4(b). The Commission complied with that obligation in the 800/900/1200 Mission Change

[2] Because the Commission does not have jurisdiction over Indian Country, EPA exercises primary authority over Class II UIC Wells located within the Southern Ute and Ute Mountain Ute Reservations. *See* 49 Fed. Reg. at 13,041; *see also* 40 C.F.R. § 147.301(a).

Rulemaking by incorporating the latest version of 40 C.F.R. Part 141 by reference.

Additionally, when the Commission revises its Class II UIC well regulations, federal law requires the Commission to keep EPA "fully informed" about the proposed modifications, and to submit documentation of the revised regulations to EPA. 40 C.F.R. § 145.32(a), (b)(1). Pursuant to this duty, the Commission's Staff conferred with EPA Region 8 staff multiple times during the course of the 800/900/1200 Mission Change Rulemaking stakeholder process, including about the initial "Straw Dog" drafts of the 800 Series Rules. The Commission will timely submit all requisite documentation of the revisions to its 800 Series Rules to EPA. *See* 40 C.F.R. § 145.32(b)(1).

Although Rule 801.a establishes standards for when injection wells will be permitted, Rule 803.e provides the criteria that the Director will apply when reviewing injection well applications. Some stakeholders requested that the Commission address the surface impacts of injection wells in Rule 801. The Commission did not adopt standards for surface impact review in Rule 801, because Rule 803.b provides that any injection well applications involving surface impacts must comply with the Commission's 300 Series Rules governing permits for surface disturbing activities, which may include obtaining approval of oil and gas development plans and/or Form 2A applications.

Rule 801.b

Consistent with its obligations as an implementing agency pursuant to C.R.S. § 25-8-202(7)(a), and in consultation with the Water Quality Control Division ("WQCD"), the Commission adopted a new Rule 802.b, clarifying that an injection well will not be authorized if the well would violate an applicable numeric or narrative domestic or agricultural groundwater quality standard or classification in Water Quality Control Commission ("WQCC") Regulations 41 or 42.

WQCC Regulations 41 and 42 serve distinct but crucial functions. The purpose of Regulation 41 "is to establish statewide standards and a system for classifying groundwater and adopting water quality standards for such classifications to protect existing and potential beneficial uses of groundwaters." 5 C.C.R. § 1002-41:41.2. In Regulation 41, the WQCC established five classifications for groundwater: domestic use, agricultural use, surface water quality protection, potentially usable quality, and limited use and quality. *Id.* § 1002-41:41.4(A). Water is classified as "domestic use" if it is already used for domestic purposes, if it is not currently used for domestic purposes but it is reasonably probable that it could be in the future based on available information, if it is permitted or decreed for domestic use by the Division of Water Resources, or background levels of applicable analytes are compliant with the WQCC's human health standards, and total dissolved solids ("TDS") are less than 10,000 milligrams per liter ("mg/l"). *Id.* § 1002-41:41.4(B)(1). A similar standard applies for agricultural use. *Id.* § 1002-41:41.4(B)(2). In turn, Regulation 42 applies this "framework for groundwater classifications and water quality standards [from Regulation 41] to specific groundwaters in the state," and also adopts interim narrative standards to protect groundwater in areas that has yet to be classified. *Id.* § 1002-42:42.2.

Thus, by implementing the WQCC's Regulation 41 and 42 standards in Rule 801.b, the Commission not only fulfills its obligation as an implementing agency under C.R.S. § 25-8-202(7)(a), but also fulfills its statutory obligation to protect public health by ensuring that groundwater is appropriately protected and remains available for use as drinking water and agricultural water. *See* C.R.S. § 34-60-106(2.5)(a).

Rule 801.c

The Commission adopted a new Rule 801.c, specifying a standard that an injection well will not be permitted if the well would inject into a formation that is not separated from an underground source of drinking water because of known faults or fractures in a confining layer. The Commission determined that standard is necessary and reasonable to protect usable groundwater from potential contamination, and to conform to federal requirements for injection wells.

The Commission declined stakeholder suggestions to adopt a maximum thickness level for confining layers, recognizing that fluids may flow through fractures or faults in even relatively thick formations. Some stakeholders also raised questions about the meaning of the term "open faults." The Commission intends for this term to be interpreted in the same way that it is interpreted for EPA's Class I UIC well requirements, which require Class I wells to be located in geologically stable areas that are free of transmissive fractures or faults through which injected fluids could travel to drinking water sources.

The Commission adopted a new 100 Series definition of Injection Zone, a term used in Rule 801.c, and throughout the Commission's 800 Series Rules. The Commission determined that defining Injection Zone provides clarity and transparency to stakeholders because the term is used very frequently in the Commission's Rules. Consistent with its delegated authority from EPA, the Commission adopted EPA's definition of the term Injection Zone from 40 C.F.R. § 144.3. However, the Commission's definition clarifies that the Injection Zone receives fluids from Class II UIC Wells, rather than all wells, to appropriately distinguish injection wells from oil and gas production wells.

For similar purposes of providing clarity and transparency to stakeholders, the Commission also adopted a new 100 Series definition of Class II UIC Well, another term used in Rule 801.c and throughout the Commission's 800 Series Rules. Again, consistent with its delegated authority from EPA, the Commission adopted EPA's definition of the term Class II UIC Well from 40 C.F.R. § 144.6(b). Because Colorado has few, if any, geological formations that allow for storage of hydrocarbons which are liquid at standard temperature and pressure, the Commission omitted the third component of EPA's definition found in 40 C.F.R. § 144.6(b)(3).

In a related change, Commission removed the definition of Dedicated Injection Well from the 100 Series Rules because the Commission determined that the definition was unnecessary. References to Dedicated Injection Wells from the Commission's prior Rules were revised to instead reference Class II UIC Wells, or disposal wells or enhanced recovery wells where additional specificity was warranted.

Rule 801.d

The Commission adopted a new Rule 801.d to specify that injection zones will not be permitted within 300 vertical feet of any Precambrian basement formation.

Rule 801.e

The Commission adopted a new Rule 801.e to codify its prior expectation and practice that operators may not inject fluids or other contaminants, including Class II waste, into a UIC aquifer that meets the 100 Series definition of an "Underground Source of Drinking Water" unless and until EPA approves an exemption for the UIC aquifer pursuant to Rule 802.e. Rules 801.a–d establish criteria for the Commission's Class II UIC well permits, and establish that the Commission will not issue a permit for an injection into an underground source of drinking water unless an operator obtains a UIC aquifer exemption pursuant to Rule 802. However, nothing in other subparts of Rule 801 expressly prohibits the *conduct* of an operator performing such an injection without a duly authorized permit and a UIC aquifer exemption approved by EPA. Accordingly, the Commission determined that it was appropriate to codify its longstanding expectation that operators will only conduct injection of Class II fluids after obtaining a permit from the Commission and after EPA gives final approval to a UIC aquifer exemption, if the injection is occurring in a UIC aquifer that would otherwise meet the definition of an "Underground Source of Drinking Water." Rule 801.e therefore fulfills the Commission's obligation pursuant to its delegated authority from EPA to implement 40 C.F.R. § 144.12(b), which prohibits the migration of contaminants into underground sources of drinking water.

Rule 802.

The Commission moved prior Rule 324B to Rule 802.

Rule 802.a

The Commission adopted a new Rule 802.a describing the purpose of UIC aquifer exemptions. If an operator seeks a permit to inject fluids into an aquifer with less than 10,000 mg/l TDS, then the operator must also seek a UIC aquifer exemption as part of the Commission's permitting process. Operators need not seek a UIC aquifer exemption as part of the 800 Series permitting process for an injection well if the proposed injection zone includes only groundwater with greater than 10,000 mg/l TDS. The Commission coordinates closely with WQCD and EPA about proposed aquifer exemptions. Consistent with the Commission's obligation to implement WQCC groundwater classifications, Rule 802 ensures that exemptions will not be granted for aquifers that currently serve as a source of drinking water or agricultural water, or could serve as a source of drinking water or agricultural water in the future. Accordingly, Rule 802.a also clarifies that the Commission will not grant a UIC aquifer exemption for groundwater formations with less than 3,000 mg/l TDS, a threshold at which water is presumptively classified as usable for drinking and agricultural purposes under WQCC regulations.

Rule 802.b

In Rule 802.b, the Commission revised both its procedural and substantive standards for UIC aquifer exemptions. Procedurally, the Commission specified that notice of a UIC Aquifer Exemption application must be provided to the WQCD. The Commission specified that coordination with the WQCD is required for a UIC Aquifer to be designated as exempt. To ensure transparency about the status and outcome of coordination with WQCD, the Commission will provide information about coordination with WQCD and the final outcome of aquifer exemptions on its website, consistent with the Commission's efforts to improve transparency about groundwater protection through the recent Wellbore Integrity Rulemaking. The Commission did not specifically require coordination with EPA in Rule 802.b, but intends for its Staff and operators to continue informally coordinating with EPA as early as possible in the application process, recognizing that EPA approval is ultimately required for all aquifer exemptions.

The Commission revised the substantive standards of Rule 802.b in several ways. As discussed above, the Commission specified that a UIC Aquifer cannot currently serve as a source of domestic water, even if it does not meet the definition of underground source of drinking water because it supplies less than 15 service connections or 25 individuals. The Commission also specified that an exempt aquifer cannot be classified for domestic or agricultural use by the WQCC.

Additionally, in determining that a formation cannot serve as a current or future source of drinking or agricultural water because it is a hydrocarbon formation, the Commission required applicants to demonstrate that a formation is currently technologically feasible to develop and can be commercially produced for hydrocarbons or geothermal energy.

The Commission also removed maximum depth limit, location, and salinity level criterion for water that could be used for drinking water or agricultural purposes from prior Rule 324B. The Commission recognizes that groundwater at depths and locations which is currently not economically or technologically practical to recover could potentially be economically recovered using future technologies. Thus, the Commission determined that it was appropriate to remove this criterion in order to protect future sources of drinking water, irrespective of current technology.

Instead, the Commission required an applicant to demonstrate that a proposed exempt UIC aquifer cannot now or in the future serve as a source of drinking agricultural water pursuant to the WQCC's groundwater standards and classification, because it is a mineral, hydrocarbon, or geothermal energy producing formation, or is so contaminated that it would be economically or technologically impractical to render the water fit for agricultural use. The Commission determined that it is appropriate to consider economic or technological practicability with respect to the degree to which groundwater is contaminated, as opposed to its location and depth, because there is no evidence in the record to suggest that groundwater that is part of a hydrocarbon formation will ever be fully recoverable for drinking or agricultural water use. To determine which formations are geothermal energy producing or have geothermal energy production potential, the Commission intends for operators to use the Colorado Geological Survey's database of geothermal energy producing areas.

To provide additional clarity and guidelines about the UIC Aquifer exemption requirements, the Commission also added a definition of UIC Aquifer to its 100 Series Rules. The 100 Series definition of UIC Aquifer is identical to EPA's definition of an "aquifer" in the agency's SDWA implementing regulations. 40 C.F.R. § 149.2. Because the Commission is exercising delegated authority to implement SDWA, the Commission determined that it was necessary to use the same definition of an "aquifer" as EPA for purposes of identifying which aquifers may be subject to the UIC Aquifer exemption.

Rule 802.c

In Rule 802.c, the Commission clarified that it will publish notice of proposed UIC Aquifer Exemption designations in not only a newspaper, but also the Commission's website. The Commission also revised the standard for parties that may request a hearing to include any interested person, to ensure that its Rules conform to EPA requirements. *See* 40 C.F.R. § 124.11. Finally, consistent with Senate Bill 19-181's changes to the relationship between the Commission and local governments, the Commission added notice to local governments of proposed aquifer exemptions.

Rule 802.d

The Commission consolidated prior Rules 324B.c and 324B.d, which both explained the process for evaluating an UIC aquifer exemption application, into a single Rule 802.d. The Commission also removed language requiring consultation with the applicant prior to determining whether a hearing will be conducted to ensure that its Rules conform to EPA requirements. *See* 40 C.F.R. § 124.11. Finally, consistent with Senate Bill 19-181's transition to a full-time Commission, the Commission revised the standard for whether a hearing will be granted if requested. Under the revised standard, a Commission hearing will occur if the Commission receives a timely hearing request within the allotted 30 day comment period, rather than the Director conducting an independent evaluation of the hearing request to determine whether a hearing should occur. At the Commission hearing, the Commission will evaluate whether the UIC aquifer exemption should be granted based on the criteria in Rule 802.b.

Some stakeholders raised questions about whether Rule 802.d would allow interested persons to request hearings about existing, previously-granted UIC aquifer exemptions. Rule 802.d would not allow interested persons to request hearings about existing UIC aquifer exemptions, because it only applies to new UIC aquifer exemption applications that are subject to the notice and comment requirements of Rule 802.c.

Rule 802.e

The Commission adopted a new Rule 802.e to codify the pre-existing requirement that EPA must review and give final approval to all UIC aquifer exemptions. As required by SDWA and its implementing regulations, after the Commission approves an UIC aquifer exemption, the Commission's Staff must submit a formal request seeking approval of the exemption to EPA. The UIC aquifer exemption only becomes effective after EPA has reviewed and approved the request, following all applicable federal regulatory requirements. Although Rule 802.e is a new regulation, it is not a change from the Commission's prior practice of submitting all UIC aquifer exemptions to EPA for formal review and approval.

Rule 803.

The Commission moved prior Rule 325 to Rule 803, and substantially revised the Rule to provide a clearer and more linear description of the permit application requirements for Class II UIC wells. Rule 803 applies to all categories of Class II UIC wells. Where applicable, the Commission specified that certain standards within Rule 803 only apply to certain categories of Class II UIC wells, such as disposal wells or enhanced recovery wells.

Rule 803.a

In Rule 803.a, the Commission consolidated prior Rules 325.c, 325.d, and 325.f into a single application process for all forms of injection wells, including disposal wells, enhanced recovery wells, simultaneous injection wells, and commercial disposal well facilities. Consolidating the application process for different types of injection wells will provide better clarity for operators and efficiency for the Commission's Staff in processing injection well applications. The same standards apply to each category of injection well unless a subsection of Rule 803 specifically excludes a particular category or categories of injection wells. Additionally, simultaneous injection well permit applications must comply with the requirements of Rule 809, commercial disposal well permit applications must comply with the requirements of Rule 810, and enhanced recovery injection project permit applications must also comply with Rule 811.

The Commission also clarified that Rule 803.a only applies to applications for new Class II UIC wells, and not retroactively to Class II UIC wells with permits approved prior to the effective date of the 800/900/1200 Mission Change Rulemaking.

Rule 803.b

In Rule 803.b, the Commission clarified its expectations for operators to comply with related 300 Series permitting requirements, and to submit Class II UIC well permit applications at the same time they submit associated 300 Series permit applications. Rule 803.b is consistent with prior Rule 325.a, which required operators to submit a Form 31 or Form 33 concurrently with a Form 2 for any new injection well. As part of moving towards a single, consolidated permitting process, the Commission intends for all permit applications to follow similar procedures and be processed concurrently. This provides greater clarity to operators, local governments, and the general public, and allows local governments and the general public to more easily engage in permitting processes that may impact them.

Which 300 Series permit applications are associated with a proposed Class II UIC well permit application will vary on a case by case basis. An operator would be required to submit a Class II UIC well permit application concurrently with an oil and gas development plan (and associated Form 2As and a Form 2B, Cumulative Impacts Data Identification) pursuant to Rule 303 for development of any new well pad. An operator would be required to submit a Form 2A pursuant to Rule 304 for any new surface disturbance at an existing oil and gas location, such as modification of an existing well pad to add a new Class II UIC well that was not contemplated in the original Form 2A application, or adding a new Class II UIC well that exceeded the total well count approved on the original Form 2A. Operators need only submit a Form 2A for any proposal that meets the requirements of Rule 304.a, such as by increasing surface disturbance or by proposing to make a significant change to the oil and gas location. As contemplated by Rule 803.b.(2), the Commission recognizes that the conversion from a production well to an injection well, alone, will not require a Form 2A pursuant to Rule 304.a, and whether a Form 2A is required will be determined on a case-by-case basis when considering whether the changes in operations attendant to the conversion are "significant."

Rules 803.b.(2).A and B are intended to ensure that the Commission and its Staff have sufficient information about the potential adverse impacts, including cumulative impacts, of converting a production well into an injection well, even if a Form 2A or oil and gas development plan is not required. Thus, for all conversion wells, operators must submit a partial Form 2B documenting incremental impacts on air quality, public health, and public welfare. Additionally, the Commission delegated discretion to the Director to require an operator to submit a subset of the information and plans required by Rules 304.b and 304.c, even if a complete Form 2A is not determined to be necessary.

Finally, an operator would be required to submit a Form 2 pursuant to Rule 308 for all proposed Class II UIC wells, regardless of whether the well is a new well or a conversion.

Some stakeholders suggested that the Commission evaluate nearby Superfund sites as part of the evaluation of Class II UIC well permits. The Commission did not adopt this suggestion because considerations about nearby surface or subsurface features that may be relevant to well siting and construction are considered as part of the associated Form 2A or Form 2 permit process. Additionally, the 400 and 800 Series Rules require complete isolation of groundwater formations surrounding the wellbore, regardless of proximity to Superfund sites or other subsurface hazards.

Rule 803.c

The Commission moved prior Rule 325.g, governing multiple injection well applications for a single lease, to Rule 803.c. The Commission clarified that this requirement applies only to disposal wells, not to all forms of injection wells. Specifically, Rule 803.c does not apply to enhanced recovery projects, which are governed by Rule 811. As discussed further below, the Commission also provided clearer guidelines about when multiple disposal wells will be permitted by specifying that the 1/4 mile injection zone radius for each disposal well cannot interfere with the injection zone radius for any other disposal well.

Rule 803.d

The Commission moved prior Rule 325.a to Rule 803.d. The Commission clarified that no injection wells may be drilled, completed, recompleted, or converted from an existing production well until the Commission approves both a Form 31, Underground Injection Formation Permit Application – Intent, and a Form 33, Injection Well Permit Application – Intent. The Commission also clarified the distinction between Form 31s and Form 33s Intent and Subsequent. For both Form 31s and Form 33s, an Intent form must be submitted and approved prior to sampling, stimulating, and performing step-rate or passive injectivity tests in a proposed well. And a Subsequent form must be submitted and approved prior to actually conducting any injection at the well, except for injection tests of limited duration and volume with the Director's prior approval. Consistent with prior practice, the Director will apply test duration and volume limits as conditions of approval for injection tests. The Commission's standard limits for injection test duration is 10 days, and for injection test volume is 10,000 barrels.

Rule 803.e

The Commission moved prior Rule 325.b to Rule 803.e. The Commission revised the criteria for the Director to deny a Form 31 or Form 33 application, consistent with Senate Bill 19-181's changes to the Commission's statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). Under Rule 803.e, the Director may deny any Form 31 or Form 33 application that the Director determines is not protective of public health, safety, welfare, the environment, and wildlife resources, and that will not protect against adverse environment impacts on any air, water, soil, or biological resource. Additionally, the Director may deny a Form 31 or Form 33 application that does not comply with any applicable Colorado water quality standards in WQCC Regulations 41 and 42. The Commission also simplified the process for an operator to appeal the denial of a Form 31 or Form 33 application to the Commission by adding a cross-reference to Rule 503.g.(10).

The criteria for denial of a Form 31 or Form 33 application in Rule 803.e are consistent with the criteria for denial of permits throughout the Commission's Rules. Rule 803.e provides a clear explanation of the criteria that will be used to make the decision to deny a permit. Agencies must provide sufficient standards to give fair notice of the criteria being used to make a decision when agencies act in a quasi-adjudicatory capacity, including in decisions to approve or deny a permit. *Farmer v. Colo. Parks & Wildlife Comm'n*, 382 P.3d 1263, 1268–69 (Colo. App. 2016). The Colorado Supreme Court has recognized that including a "reasonableness" requirement is enough to satisfy the fair notice test. *Douglas Cty. Bd. of Comm'rs v. Pub. Utils. Comm'n*, 829 P.2d 1303, 1312 (Colo. 1992). Rule 803.e includes much more than a reasonableness requirement. It includes the statutory criteria such as the protection of public health, safety, welfare, the environment, and wildlife resources and protecting against adverse impacts on air, water, soil, and biological resources. It also includes the aforementioned requirement of compliance with applicable Colorado water quality standards. Finally, consistent with Rule 301, the Commission and Director will evaluate all permit applications, including Form 31 and Form 33 applications, for consistency with the Commission's Rules and the Oil and Gas Conservation Act.

Rule 803.f

In Rule 803.f, the Commission expanded prior Rule 325.d.(7)'s provisions relating to maximum allowable injection rates and pressures that previously applied only to dedicated injection wells. The Commission added a new objective, performance-based standard for maximum allowable injection rates and pressures, by requiring that injection pressures not initiate any new fractures or propagate existing fractures. This standard will ensure that no fluids migrate out of the approved injection zone.

In Rule 803.f.(1), the Commission specified standards for seismic monitoring that the Director may require as conditions of approval on a Form 31 or Form 33 – Subsequent. Because evidence in the administrative record demonstrates that high injection rates are likely to be a risk factor for induced seismicity, Rule 803.f.(1) requires seismic monitoring for any disposal wells that exceed an injection rate of 10,000 barrels of water per day. In addition, Rule 810.b requires seismic monitoring for all commercial disposal wells, which typically have higher injection rates. Additionally, the Commission's Staff will review seismic evaluations submitted pursuant to Rule 803.g.(6), as well as other available information, to determine if the unique geologic setting and rates or cumulative volumes of fluids (including both liquids and gases) injected into a proposed UIC well may pose a specific risk of induced seismicity. In such a case, the Commission or its Staff would require seismic monitoring, as reasonable and necessary, to monitor seismic activity. The Commission recognizes enhanced recovery wells pose significantly lower risks of induced seismicity than disposal wells, but Rule 803.f.(1) nevertheless recognizes that seismic monitoring could be appropriate in unusual cases where high injection rates or other factors would result in an elevated risk of induced seismicity at an enhanced recovery well.

The Commission instructs its Staff to issue guidance about seismic monitoring protocols that may be required, which will include additional information about the "traffic light" protocol. Consistent with prior practice, Rule 803.g.(6) specifies that the Commission Staff may use a traffic light protocol as part of the seismic monitoring condition of approval. A traffic light protocol uses a three tiered green, amber, and red color-coded warning system to identify specific thresholds of monitored seismic activity that require certain actions to be taken. Specifically, the traffic light system would cross-reference various metrics of seismic activity, including the modified Mercalli scale, the magnitude of an earthquake, peak velocity, peak acceleration, potential damage, and perceived shaking, to thresholds of required response. A "green" designation would allow an operator to continue operations. An "amber" designation would require an operator to modify operations. And a "red" designation would require an operator to suspend operations.

The Commission's Staff have successfully worked with an operator to implement a traffic light protocol as a seismic monitoring practice prior to the 800/900/1200 Mission Change Rulemaking, and intend to continue to require the use of this practice where appropriate. Although the Commission intends for a traffic light protocol to be one potential condition of approval that will be applied for seismic monitoring, the Commission determined that it was not appropriate to codify specific thresholds for a traffic light protocol on a statewide basis in the 800 Series Rules. Because Colorado's geologic settings vary widely between oil and gas producing geologic basins, and because the unique local geology will determine what specific seismic risks a Class II UIC well may present, as well as which thresholds of seismicity are appropriate to identify in the traffic light protocol, the Commission determined that identifying statewide seismicity thresholds in its Rules would not be an effective way of implementing a seismic monitoring protocol, and that these thresholds should instead by identified on a case by case basis. However, the Commission intends for its Staff to provide more detailed information about the traffic light protocol, which may vary between geologic basins or fields, in guidance.

Some stakeholders suggested that the Commission adopt seismic monitoring requirements for hydraulic fracturing processes in addition to Class II UIC well injection. The Commission did not adopt this recommendation because, although low levels of induced seismicity are associated with hydraulic fracturing, the magnitude of this seismicity is usually orders of magnitude below that attributed to injection wells. The Commission is not aware of any evidence in Colorado that this low magnitude seismicity associated with hydraulic fracturing has caused damage, or has been felt at the surface.

In Rule 803.f.(2), the Commission specified maximum allowable injection pressures for injections that are not hydraulic fracturing, to ensure that injections do not initiate new fractures or propagate new fractures.

In Rule 803.f.(4), the Commission codified its prior practice that operators must submit requests to increase disposal well injection zone radii from 1/4 mile to 1/2 mile to the Director via a Form 4, Sundry Notice.

Rule 803.g

In Rule 803.g, the Commission consolidated the standards for Form 31 applications that were previously located throughout prior Rule 325 into a single Rule to provide greater clarity to operators and the general public. Throughout Rule 803.g, the Commission also clarified which requirements apply only to disposal wells and which standards apply only to enhanced recovery projects.

Rule 803.g.(1)

The Commission moved prior Rule 325.h, governing who may submit a Form 31 application, to Rule 803.g.(1).

Rule 803.g.(2)

The Commission broke the map and list of persons who must receive notice into subsections for clarity. Consistent with Rule 803.c, in Rule 803.g.(2), the Commission increased the radius for providing a map and list of contact information for surface and mineral owners from 1/4 mile to 1/2 mile. Under the Commission's prior Rules and EPA's federal standards, a disposal well applicant is only required to provide notice to surface and mineral owners within 1/4 mile of a proposed Class II UIC well. *See* Prior Rule 325.i; 40 C.F.R. § 144.31(e)(9). However, although a Class II UIC well approved on a Form 31 may initially only inject a volume of fluids that could fill pore space within a 1/4 mile radius based on the thickness and porosity of the formation targeted for the injection, operators may later seek approval to increase the volume to an injection radius of up to a maximum of 1/2 mile. Accordingly, the Commission determined that it was necessary for operators to collect the contact information of surface and mineral owners within a broader radius, because a Form 31 may ultimately result in a permitted injection of fluids in a radius of up to 1/2 mile. As discussed below, the Commission also increased the area of review for a proposed injection well from 1/4 mile to 1/2 mile in Rule 803.g.(9), and increased the radius in which surface and mineral owners must receive notice of a disposal well from 1/4 mile to 1/2 in Rule 803.g.(14).B.

Rule 803.g.(3)

In Rule 803.g.(3), the Commission added a new regulatory requirement that operators provide evidence of an agreement for any Form 31 application to construct or recomplete a proposed injection well at the surface location. Rule 803.g.(3) does not apply if the operator applying for a permit for a Class II UIC well is also the surface owner. Prior Commission policy and practice required surface use agreements, lease terms, or a unit agreement for proposed injection wells, and the Commission determined it was necessary to codify that policy in order to provide greater clarity to operators, surface owners, mineral owners, and the public at large. To provide better clarity, the Commission identified separate standards for disposal and simultaneous injection wells, for which operators must provide surface use agreements, and enhanced recovery wells, for which operators may provide surface use agreements, copies of leases, or unit operating agreements, as applicable. In Rule 803.g.(3).C, the Commission provided substantive standards for what the surface use agreements, leases, or unit operating agreements must address, which includes a description of the fluids that will be injected.

Consistent with changes throughout the 800 Series Rules, the Commission also clarified that Rule 803.g.(3)'s requirements will apply within a 1/2 mile radius of an injection well if an operator submits a Form 4 pursuant to Rule 803.f.(4) to increase the injection radius from 1/4 mile to 1/2 mile.

The surface use agreement requirement not only serves the purpose of ensuring that surface owners are aware of and agree to equipment on their surface property, but also is necessary to ensure that surface owners have notice that operators intend to access subsurface pore space. Some states apply distinct property rights regimes to oil and gas formations and subsurface pore space.

Rule 803.g.(4)

The Commission moved prior Rule 325.c.(4) to Rule 806.g.(4), and clarified that the surface facility diagram should also include a process flow diagram so that it is clear to a person reviewing the diagram how fluids move through the pipelines and tanks included in the diagram.

Rule 803.g.(5)

In Rule 803.g.(5), the Commission consolidated several requirements from prior Rules 325.c and 325.d into a single description of a proposed injection program, addressing the basic details of the geologic formation targeted for injection, quality, volume, and source of fluids proposed for injection, and processes related to the transport and injection of fluids.
In Rule 803.g.(5).B, governing geologic formation summaries, the Commission clarified that if there is limited data available about the geologic formations below the target formation, an operator may provide a best estimate of the depth to the Precambrian basement, rather than an exact number.

In Rules 803.g.(5).C and D, the Commission revised its standards for analysis of injection fluid sampling and analysis (Rule 803.g.(5).C) and injection zone sampling and analysis (Rule 803.g.(5).D). Under the revised standards, operators must comply with the sampling and analysis procedures for produced water samples in Rules 909.j.(1)–(5), including the list of analytes in Rule 909.j.(1). In the unusual circumstance in which a proposed injection well is intended to serve production wells that are not yet completed, an operator may submit other data available that provides information about the characteristics of the fluid that the operator anticipates will be injected—for example, sampling data from other nearby production wells that are producing from the same targeted formation. Should this occur, the operator would be required to submit a laboratory analysis of a representative sample of the actual fluid to be injected within 90 days of the commencement of production at a production well that will send or is sending fluids to be injected at the Class II UIC well.

In Rule 803.g.(5).D, the Commission further clarified that operators must evaluate injection zones for hydrocarbon potential by adding a cross-reference to Rule 408.q. Finally, Rule 803.g.(5).D clarified that operators may provide water sampling data from nearby offset wells within a one mile radius as baseline data with a Form 31 – Intent application. The Commission determined that these changes to sampling and analysis protocols were necessary to provide additional clarity to the regulated community, and also ensure that the Commission has robust baseline data about water quality in the injection formation prior to injection occurring. The Commission recognizes that there may be situations where water sampling may be difficult because of inadequate flow into the well. In such a situation, the Commission expects that the operator will use other means to characterize the reservoir fluids, and will work with Staff on a case-by-case basis to determine an appropriate approach.

Consistent with the revisions to Rule 803.g.(5), the Commission adopted a new 100 Series Definition of the term Fluids, based on a similar definition used by the New Mexico Oil Conservation Division. The Commission determined that adopting the definition to clarify for stakeholders that the Commission's Rules use the term "Fluids" to refer to not only liquids, but also substances in semisolid and gaseous forms or states.

Rule 803.g.(6)

In Rule 803.g.(6), the Commission adopted new standards for seismicity evaluations. Seismicity evaluations are intended to provide the Commission's Staff with background information about the geologic setting of a proposed Class II UIC well. This information will provide the Director with information necessary to ensure that injection well applications comply with the standards in Rules 801.c and 801.d. Seismicity evaluations will also provide the Commission's Staff with information necessary to determine whether seismic monitoring may be warranted as a condition of approval pursuant to Rule 803.f.(1). The Commission instructed its Staff to issue guidance to reflect the regulatory changes, and to provide additional instructions for operators about how to conduct a seismicity evaluation, as discussed below.

The Commission determined that Rule 803.g.(6) is necessary because without proper precautions, injection wells may induce seismicity.[3] The Commission therefore adopted reasonable and necessary precautions to ensure that proposed injection wells do not induce seismicity. High-magnitude earthquakes induced by injection wells are rare, but have been recorded in other states and nations. In Colorado, there have been only a limited number of known induced seismicity instances linked to injection wells. Although evidence links seismic activity in the Raton Basin to injection wells

[3] *See generally* Justin L. Rubinstein & Alireza Babaie Mahani, *Myths and Facts on Wastewater Injection, Hydraulic Fracturing, Enhanced Oil Recovery, and Induced Seismicity*, 86 Seismological Res. Letters 1 (2015).

in the area, the propensity for natural seismicity in the area makes it more difficult to conclude with certainty the degree to which seismic activity in the Raton Basin is linked to injection wells.[4]

Accordingly, the Commission determined that a robust seismicity evaluation is necessary for all proposed injection wells, including both disposal wells and enhanced recovery wells. The Commission recognizes that there is likely a lesser risk of induced seismicity associated with enhanced recovery wells than disposal wells. However, the Commission determined that a seismicity evaluation is nevertheless necessary for enhanced recovery wells, because a nearby fault could pose risks of induced seismicity at an enhanced recovery well.

A core component of the seismicity evaluation is ensuring that there are no known faults within the vicinity of the proposed injection well that could increase the potential for seismic activity (or fluid migration) based on maps and narratives submitted by an operator pursuant to Rule 803.g.(6).A. The fault evaluation required by Rule 803.g.(6).A is not intended to require an operator to create a perfect map of the subsurface. Rather, the Commission intends for operators to conduct a broad evaluation. Operators need not create or gather new data or conduct seismic studies. Rather, the Commission intends for operators to rely on available information, including publicly-available information from the U.S. Geological Survey ("USGS"). The purpose of Rule 803.g.(6).A is for a trained geologist to review seismic activity within a 12-mile radius of a proposed Class II UIC well, evaluate potential risks, and explain what those risks are to the Commission in a permit application.

The Commission chose a 12-mile radius for the fault evaluation as a precautionary measure to ensure that all potential fault zones are identified and evaluated. Other states that have adopted analogous seismicity evaluation standards is have assumed that impacts of induced seismicity may occur within ten kilometers (6.2 miles) of an injection. Accordingly, the Commission views the 6.2 mile radius as distance in which there is a higher probability of induced seismicity. Evidence in the administrative record suggests that a greater distance may warranted for seismicity evaluations in Colorado compared to other states because of Colorado's unique geology. For example, the unique geologic setting of the Raton Basin has resulted in impacts from prior seismicity events that may have been induced being experienced at a radius greater than 6.2 miles. Because of the widely varying geologic settings that are present throughout Colorado, the Commission determined that an abundance of

[4] *See* J.S. Nakai *et al.*, *A Possible Causative Mechanism of the Raton Basin, New Mexico and Colorado Earthquakes Using Recent Seismicity Patterns and Pore Pressure Modeling*, 122 J. Geophysical Res.: Solid Earth 8051 (2017); Justin L. Rubinstein *et al.*, *The 2001–Present Induced Earthquake Sequence in the Raton Basin of Northern New Mexico and Southern Colorado*, 104 Bull. Seismological Soc'y of Am. 1 (2014).

caution warranted evaluating a wider radius to determine whether there is a need for additional conditions of approval to be added with respect to depth of injection, volume restrictions, or seismic monitoring as part of the Form 31 review process. With that perspective in mind, and consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), the Commission adopted a larger 12-mile radius for evaluation out of an abundance of caution to minimize potential adverse impacts to public health, safety, welfare, the environment, and wildlife resources that could be caused by an induced seismicity event.

In Rule 803.g.(6).B, the Commission required operators to submit an exhibit demonstrating historical seismic activity within a 12-mile radius of the proposed injection well site. Although operators may use any source available to them to acquire information for this exhibit, the Commission will issue guidance instructing operators about how to use the USGS Earthquake Catalog. *See* USGS, *Earthquake Catalog*, https://earthquake.usgs.gov/earthquakes/search/ (last visited November 17, 2020). The Earthquake Catalog is continuously updated, and can be searched by magnitude, date and time, and geographic region. Users can draw a rectangle around the area of interest on the map. Accordingly, the USGS Earthquake Catalog will provide the information necessary to create the historical seismic activity exhibit required by Rule 803.g.(6).B.

In Rule 803.g.(6).C, the Commission required operators to submit an exhibit demonstrating potential for seismic activity within a 12-mile radius of the proposed injection well site. Recognizing that the best available information may change over time, the Commission did not limit Rule 803.g.(6).C to adopting any single method for demonstrating the potential for seismic activity, which provides flexibility in the event that changes are necessary in the future. However, at the time of the 800/900/1200 Mission Change Rulemaking, the Commission determined that the best available information is the USGS Seismic Hazard Map database. Accordingly, the Commission interprets the term "potential" in Rule 803.g.(6).C to reference the two probability metrics used in the USGS Seismic Hazard Map database. The Commission therefore intends for this exhibit to take the form of a narrative description of information from the USGS Seismic Hazard Map database, along with any appropriate visual documentation such as screenshots or maps. The Commission will issue guidance instructing operators about how to prepare this exhibit, and how to use the USGS Seismic Hazard Maps. *See* USGS, *Seismic Hazard Maps and Site-Specific Data*, https://www.usgs.gov/natural-hazards/earthquake-hazards/seismic-hazard-maps-and-site-specific-data (last visited November 17, 2020). Within the USGS Seismic Hazard Map data, users can select the most recent long-term and short-term maps for the continental United States, which identify two statistical measures of "potential" for seismic activity: the short-term probability of at least a "minor" earthquake occurring, and areas with at least a 2% peak ground acceleration probability within 50 years.

Rule 803.g.(7)

The Commission consolidated portions of prior Rules 325.c.(2) and 325.d.(2) into Rule 803.g.(7), which requires operators to submit a map and list of oil and gas wells within a one-mile radius of a proposed disposal well. Like the offset well evaluations required by Rules 408.t–x, this information is necessary for the Commission's Staff to identify potential migration pathways for injected fluids and ensure that disposal wells are constructed and operated in a manner that will not allow fluid migration. The Commission also clarified confusing language in its prior Rules to provide precise requirements for mapping protocols. Enhanced recovery wells are required to submit equivalent information under Rule 811.b.(8).

Rule 803.g.(8)

The Commission consolidated portions of prior Rules 325.c.(2) and 325.d.(2) into Rule 803.g.(8), which requires operators to submit a map and list of all water wells within a one-mile radius of a proposed injection well. As with Rule 803.g.(7), this information is necessary for the Commission's Staff to identify potential migration pathways for injected fluids and ensure that injection wells are constructed and operated in a manner that will not allow fluid migration. Operators may obtain water well permit and construction information from the Colorado Division of Water Resources.

Rule 803.g.(9)

In Rule 803.g.(9), the Commission created a 1/2 mile area of review requirement for Form 31 applications. As discussed above, the 1/2 mile radius is important because a Form 31, though initially intended to permit an injection radius of only 1/4 mile, may be subsequently increased to permit an injection radius of 1/2 mile. Accordingly, it is necessary for operators to conduct a full review of any existing offset wells (including both active and abandoned wells, and both oil and gas and domestic/irrigation water wells) and any other potential migration pathways within a 1/2 mile radius to ensure that groundwater is protected from contamination. The area of review evaluation will also allow the Form 31 applicant to demonstrate to the Commission's satisfaction that all formations, including underground sources of drinking water, are properly isolated.

Rule 803.g.(10)

The Commission consolidated portions of prior Rules 325.c.(2) & (4) and 325.d.(2) & (4), governing remedial corrective action plans, into Rule 803.g.(10). The Commission revised the language of Rule 803.g.(10) to ensure that it conforms with EPA's requirements for corrective action. *See* 40 C.F.R. § 144.55. The remedial corrective action plan allows operators to demonstrate to the Director's satisfaction that any wells in the area of review penetrating the injection zone will be plugged or fully isolated with cement for multiple well applications or enhanced recovery projects. The corrective action plan must address all offset wells within 1/4 mile of a disposal well, a simultaneous injection well, or a single-well enhanced recovery project for the initial application approval. The Commission extended corrective action plan requirements to 1/2 mile of a disposal well or simultaneous injection well when a volume increase is considered. Operators must perform and verify all corrective actions prior to injection in order to ensure that no injected fluids migrate out of the injection zone. A remedial corrective action plan is required for all wells within the unit for multiple well enhanced recovery projects. However, remedial corrective action plans are not required for enhanced recovery projects where the offset well is a producing well that is part of the project.

As with all enforcement actions, the Commission will coordinate closely with its federal agency partners for remedial corrective actions plans for wells located on federal surface or mineral estate.

Rule 803.g.(11)

The Commission consolidated prior Rules 325.c.(6) and 325.d.(5) into a single Rule 803.g.(11), requiring Form 31 applicants to submit a summary of any proposed stimulation.

Rule 803.g.(12)

Consistent with prior Rule 325.m.(1), the Commission adopted a new Rule 803.g.(12), requiring a Form 31 to include a description of the potential hydrocarbon production potential for any disposal well. This requirement applies only to disposal wells, not enhanced recovery wells. The Commission does not intend for disposal wells to inject fluids into producible hydrocarbon formations, and accordingly an evaluation of the hydrocarbon production potential of the formation targeted for injection is necessary.

Rule 803.g.(13)

The Commission moved prior Rule 325.c.(5) to Rule 803.g.(12). Consistent with Rules 807 and 905.c.(2).D.i, Class II UIC well operators must track both the source of and ultimate disposal location of all injected produced water by submitting one or more Form 26, Source of Produced Water for Disposal.

Rule 803.g.(14)

The Commission consolidated the notice provisions of prior Rules 325.i, 325.j, 325.k, and 403 into a single Rule 803.g.(14). Rule 803.g.(14) provides clearer, more streamlined procedures for operators to provide notice of injection well applications to mineral owners, surface owners, and local governments. Rule 803.g.(14).A requires notice to a local government with land use authority within 1/2 mile of a proposed injection well, rather than notice to a proximate local government. This is because the Commission's 100 Series Rules define a "Proximate Local Government" as a local government with land use authority within 2,000 feet of a proposed working pad surface. Rule 803.g.(14).A is intended to provide notice to nearby local governments, but because Rule 803.g.(14) involves permit applications for injection wells, rather than oil and gas locations, and because the notice radius is 2,640 feet, rather than 2,000 feet, the Rule uses the term "local government with land use authority within 1/2 mile of a proposed injection well," rather than the term "Proximate Local Government."

Rule 803.g.(14) provides the notice requirements for operators at the time they submit an injection well permit application. This is distinct from the notice requirements of Rule 804, which govern the public notice that is provided by the Director about proposals to approve or deny complete injection well permit applications. The notice provided by operators pursuant to Rule 803.g.(14) is analogous to the notice operators provide about an oil and gas development plan pursuant to Rule 303.e.(1) The public notice provided by the Director pursuant to Rule 804 is analogous to the Director's public notice of a recommended decision about whether to approve or deny a proposed oil and gas development plan pursuant to Rule 306.c.

Although analogous, the notice provisions of Rules 803.g.(14).A, B, and C are different than the notice required under by Rule 303.e.(1) in several ways. Many of these differences are rooted in the distinct purposes for notice provided by Rule 803.g.(14) and the 300 Series Rules. Most of the notices provided in the 300 Series are intended to notify persons who may potentially be impacted by surface activities. By contrast, the notices in Rule 803.g.(14) are generally intended to notify surface owners and mineral owners of proposed activities within or near their property that may impact their subsurface property rights.

First, Rule 308 does not include public notice requirements for Form 2 applications. Thus, for any injection well permit application that does not require a Form 2A pursuant to Rules 803.b and 304.a, notice to nearby mineral and surface owners would not otherwise be required through the simultaneous 300 Series permitting process. Accordingly, the Commission required such notice for injection well permit applications pursuant to Rule 803.g.(14).

Second, Rule 303.e.(1) requires operators to provide notice of oil and gas development plans (and Form 2As) to owners of minerals that will be subject to development, and surface owners within 2,000 feet of the working pad surface. Because not all mineral owners within 1/2 mile of a proposed injection well will necessarily be owners of minerals that are "subject to development" by the proposed injection well, it is necessary to add an additional notice provision for those mineral owners for a Form 31. Additionally, 2,000 feet is less than 1/2 mile, which is 2,640 feet, so an additional notice provision is necessary to notify surface owners of property located between 2,000 and 2,640 feet from a proposed injection well. As discussed above in Rule 803.g.(3), the Commission determined that mineral and surface owners within 1/2 mile of a proposed injection well should receive notice, and therefore Rule 803.g.(14).B requires those mineral and surface owners to receive notice. For applications to increase the injection zone radius from 1/4 mile to 1/2 mile, notice must be provided to all surface and mineral owners and local governments within 3/4 miles of the injection well location. Extending the notice radius to 1/4 mile beyond the area of review ensures that all potentially impacted property owners and local governments receive adequate notice, with a reasonable margin of error.

Rule 803.g.(15)

The Commission moved prior Rule 325.l to Rule 803.g.(15), providing substantive requirements for notice of injection applications. Among other things, Rule 803.g.(15).A requires the notice provided to nearby surface owners, mineral owners, and local governments to explain that they may petition for a hearing pursuant to Rule 507.

Rule 803.h

In Rule 803.h, the Commission consolidated all requirements for a Form 31 – Subsequent into a single Rule, including parts of prior Rules 325.c.(1) & (3) and 325.d.(1) & (3) governing injection zone water quality analysis and geophysical logs. The Commission determined that it is important for its Staff to receive reports back about key factors that operators identify during the initial testing of a proposed injection well as a component of the application process. Consistent with Rule 803.g.(5), the Commission required water analysis performed for the injection formation to conform to the sampling and analysis requirements of Rules 909.j.(1)–(5).

For the geophysical log requirement of Rule 803.h.(2), the Commission intends that new wells will have a suite of open-hole gamma ray, electrical resistivity, and density-porosity logs. In instances where open hole logs have not been or cannot be run, the Commission intends to allow operators to submit historic geophysical logs where available, so long as the log uses downhole measurement techniques to identify formation characteristics and fluid properties. The Commission also added two new components for a Form 31 – Subsequent: hydrocarbon productivity evaluations and the results of any step rate or injectivity tests. Although these latter two tests will not be conducted for every well, when an operator does conduct them it is important for the Commission's Staff to have access to the results.

Rule 803.i

In Rule 803.i, the Commission consolidated components of its prior Rules 325.a, 325.c.(4), 325.d.(4), 325.d.(7), and 404 into a single Rule governing Form 33 – Intents. Form 33 – Intents must provide all information pertinent to the Commission's Staff ensuring that wells are constructed properly to maintain integrity and isolate fluids, including a wellbore diagram and a casing and cementing plan. The Commission intends for the casing and cementing plan required by Rule 803.i.(2) to be a grid provided on a Form 33, not an attachment to the form, consistent with changes the Commission made to the Form 2 casing and cementing plan in its recent Wellbore Integrity Rulemaking. Casing and cementing plans therefore must comply with the requirements for casing and cementing plans for a Form 2 pursuant to Rule 308.b.(6).

The Commission also clarified that casing integrity checks apply only to existing wells that an operator proposes to convert to a Class II UIC well.

Rule 803.j

In Rule 803.j, the Commission consolidated components of its prior Rules 325.a, 325.c.(4), 325.d.(4), 325.e, and 404 into a single Rule governing Form 33 – Subsequents. A Form 33 Subsequent must be submitted after an injection well is drilled to verify that the wellbore maintained integrity during the drilling process, passed a mechanical integrity test, that all casing and cementing is adequate, and that all fluids will be isolated during the injection process. As with Form 33 Intents, the Commission intends for the casing and cementing plan required by Rule 803.j.(1).B to comply with Rule 308.b.(6) and to be a grid provided on a Form 33, not an attachment to the Form, consistent with changes the Commission made to the Form 2 casing and cementing plan in its recent Wellbore Integrity Rulemaking.

Rule 803.k

The Commission moved prior Rule 325.o to Rule 803.k. The Commission revised the wording of the Rule to provide additional clarity to operators about when they must submit all information necessary to complete a Form 31 – Subsequent or Form 33 – Subsequent application. Under ordinary circumstances, operators have 6 months from the date that a Form 31 – Intent or Form 33 – Intent is approved to submit all information required by the Commission's Staff to review a Form 31 – Subsequent or Form 33 – Subsequent. However, operators may submit a Form 4 requesting a 90 day extension of this period for good cause.

Consistent with other permitting standards in the Commission's 300 Series Rules, the Commission did not adopt a time limitation for the Commission's Staff to process Form 31 or Form 33 applications, recognizing that the complexity of applications will vary on a case by case basis. Additionally, EPA does not limit the timeframe for agencies with delegated authority to process Class II UIC well permit applications.

Rules 803.l and 803.m

The Commission moved prior Rule 405, governing notice of commencement and discontinuance of injection operations, to Rules 803.l and 803.m.

In Rule 803.l, consistent with the Commission's Form 5A, Completed Interval Report requirements, the Commission clarified that operators must immediately provide notice of the commencement of injection on a Form 5A.

In Rule 803.m, the Commission clarified that operators must provide notice of discontinuance of injection operations on a Form 4. The purpose of a notice of discontinuance is to notify the Commission's Staff that a well is no longer being used as an injection well. This enables the Commission's Staff to correctly track whether a well is being used for injection purposes within its internal and external databases. Thus, if an operator declares a well is no longer an injection well, a notice of discontinuation is required.

Notices of discontinuance are not intended to notify the Commission's Staff about brief interruptions in injection activities. Accordingly, the Commission amended the language of Rule 803.m to clarify that operators need not submit notices of discontinuance for status changes to and from injection and production for enhanced recovery projects. Notices of status changes between injection and production for enhanced recovery projects are governed by Rule 811.d.

Rule 803.n

The Commission moved prior Rule 405.d to Rule 803.n. When an owner or operator intends to plug a Class II UIC well, they must notify the Commission. The Commission revised prior Rule 405.d to provide additional clarity, and to specifically cross-reference the well plugging requirements of Rule 434.

Rule 804.

Rule 804 provides the procedural requirements for Class II UIC well permit applications. The Commission determined that it would provide more clarity to members of the public if the procedural requirements for permit applications were consolidated into a single rule, rather than being a part of Rule 803. The Commission revised and expanded upon its prior procedural requirements to provide more clarity about how the public can participate in Class II UIC well permit application processes. The Commission further revised the requirements to clarify the relationship between the 800 Series Class II UIC well permitting process and the 300 Series location and well permitting process and 500 Series hearing process. The public notice provided by Rule 804 and notices provided by the 300 Series Rules have distinct purposes. Notice to parties who may be affected by potential surface impacts is governed by the 300 Series Rules, as part of the Form 2A permitting process for activities with surface impacts. By contrast, the notice that operators provide pursuant to Rule 803.g.(14) is intended to notify nearby property owners (of both the mineral and surface estate) of proposed activities that could potentially impact their subsurface property rights. Rule 804 combines these two functions by allowing interested persons to comment on and protest Class II UIC well permits, by providing broad notice to all members of the general public on the Commission's website and in newspapers.

Rule 804.a

The Commission moved prior Rule 325.n to Rule 804.a, and revised the Rule to provide greater transparency and clarity about opportunities for public engagement in Class II UIC well permit applications. Consistent with transitioning into a single, consolidated application process for all forms of Class II UIC wells, the Commission expanded the scope of the public notice requirements to apply to all injection well applications, rather than only applications for disposal wells.

Prior Rule 325.n stated that the Director would provide public notice of an injection well through newspaper publication, as required by EPA. *See* 40 C.F.R. §§ 124.10(c)(2)(i); 145.11(a)(28). The Commission amended Rule 804.a.(1) to also provide public notice on the Commission's website.

The Commission also codified its prior practice of simultaneously providing notice to the Division of Water Resources. The Commission provides notice to the Division of Water Resources because the Division's Dam Safety Program is responsible for ensuring dam safety and managing risks to dams. Induced seismicity related to Class II UIC wells could potentially pose risks to dam safety, so the Commission determined that it is important to ensure that the Dam Safety Program has the opportunity to provide comments or feedback about any potential risks to dams during the permitting process.

In Rule 804.a.(3), the Commission clarified that the timing for the 30 day comment period is based on the date that notice is published in a newspaper, rather than publication on the website.

In Rule 804.a.(4), the Commission clarified that any interested person may electronically submit comments about the injection well permit application during the 30-day comment period. The interested person standard in Rule 804.a.(4) is different than the affected person standard in Rule 507.a. The Commission maintained a different standard for who may submit comments on injection well permit applications because EPA regulations provide that "any interested person may submit written comments on the draft permit . . . and may request a public hearing." 40 C.F.R. § 124.11; *see also id.* § 145.11(a)(29).

Further consistent with EPA regulations, in Rule 804.a.(5), the Commission identified the process for interested persons to submit a written protest of the injection well permit application in order to request a Commission hearing about the permit application.

In Rule 804.a.(5), the Commission also clarified the relationship between the Commission's 500 Series Rules and the 800 Series Rules. As discussed above, pursuant to Rule 803.b, injection well permit applications that involve new surface disturbance or significant changes to an existing location will be submitted concurrently with an oil and gas development plan application and will already be subject to a Commission hearing pursuant to Rule 503.g.(10). Accordingly, there is no need for a protest of such an injection well permit application to separately request a Commission hearing. Rather, the protest of the injection well permit application will be heard as part of the Commission's hearing about the proposed oil and gas development plan.

However, for injection well permit applications that do not require submitting an oil and gas development plan or Form 2A, the associated 300 Series permit application will be a Form 2, and there will not otherwise be a Commission hearing on the permit application. Accordingly, protests of this category of permit must also submit an application for a Commission hearing pursuant to Rule 503.g.(10).

Finally, Rule 804.a.(5) clarifies that Rule 804.b provides the standard the Commission will use to evaluate protests filed under Rule 804.a.

Rule 804.b

The Commission moved prior Rule 325.m to Rule 804.b, and also updated cross-references and clarified confusing language. The Commission removed language requiring consultation with the applicant prior to determining whether a hearing will be conducted to ensure that the Commission's Rules conform to EPA requirements. *See* 40 C.F.R. § 124.11. Additionally, consistent with Senate Bill 19-181's transition to a full-time Commission, the Commission revised the standard for whether a hearing will be granted if requested. Under the revised standard, a Commission hearing will occur if the Commission receives a timely hearing request pursuant to Rule 804.a.(5) within the allotted 30 day comment period, rather than the Director conducting an independent evaluation of the hearing request to determine whether a hearing should occur. At the Commission hearing, the Commission will evaluate whether the injection well permit application should be granted or denied based on the criteria in Rule 804.b.

Consistent with the Commission's revisions to Rule 802 to consider both current and potential future uses of groundwater for both drinking water and agricultural water, the Commission amended Rule 804.b.(2) to provide that the considerations the Commission will evaluate in a hearing include whether the proposed operations at the proposed Class II UIC well are protective of current and potential future uses of both drinking and agricultural water.

Finally, the Commission added new Rules 804.b.(3) & (4), providing that written protests should address whether the proposed injection well protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and complies with applicable Colorado water quality standards including the WQCC's numeric and narrative standards and classifications in Regulations 41 and 42.

Rule 805.

The Commission moved prior Rule 324C to Rule 805. The Commission expanded the analytical and quality assurance requirements for injection fluid analysis in order to provide clearer, objective standards for operators, and to protect public health, safety, welfare, the environment, and wildlife resources.

Rule 805.a

In Rule 805.a, the Commission clarified that Rule 805's analytical and quality assurance requirements apply to specific types of water samples required by the Commission's 800 Series Rules. The Commission also clarified that the reference to a quality assurance project plan in prior Rule 324C is intended to be a reference to an Underground Injection Control Quality Assurance Project Plan, as defined by the EPA.

Rule 805.b

In Rule 805.b, the Commission specified that all injection fluid analyses must include at least TDS. The Commission explained its intent that operators adhere to either standard EPA or oilfield sampling methods, without requiring operators to adhere to any specific sampling method in every instance, recognizing that the methodology used may need to vary on a case-by-case basis.

Rule 805.c

In Rule 805.c, the Commission added a requirement that the Commission's Staff may require operators to analyze samples for additional constituents. The Commission recognized that its Staff may identify situations in which there are constituents of concern beyond those that an operator initially analyzed, or where a sample collected by an operator indicates a need for further sampling to ensure that injection protects public health, safety, welfare, the environment, or wildlife resources.

Rule 805.d

In Rule 805.d, the Commission specified that water samples must be reported electronically to the Director on a Form 43, Analytic Sample Submittal, through the Commission's environmental database.

Rule 806.

The Commission added a new Rule 806 to provide clear, objective standards for when injection fluid samples must be taken. Providing specific regulatory guidance about when samples must be taken will enable operators to better understand the scope of sampling requirements, and ensure that samples are taken at each important juncture in the injection process. The Commission specified that all samples must be representative samples. The Commission intends for its Staff to clarify standards for what constitutes a representative sample in the instructions for the Form 26.

The Commission adopted requirements for an initial analysis of the injection fluids within a year after commencing injection, then periodic analysis of injection fluids every 5 years, and at any time that an injection fluid changes at both new and existing injection wells. Changes in fluid would include but not be limited to addition or deletion of a group of source wells such as from a new field or closure of an old field. This periodicity of sampling will ensure that the Commission and operators have adequate data to understand the contents and quality of injection fluids, and will be able to identify and address any changes in the contents or quality that may impact public health, safety, welfare, the environment, or wildlife resources. However, the Commission recognizes that some wells will not change injection fluids frequently, and accordingly adopted a reasonable 5-year periodic requirement to avoid unduly burdening those wells with relatively static injection fluid sources, while still providing the Commission with information about any changes in injection fluid characteristics over time.

Consistent with Rule 803.g.(5) and 803.h, the Commission required injection fluid analysis performed for significant changes to conform to the sampling and analysis requirements of Rules 909.j.(1)–(5). Among other things, Rule 909.j.(3) requires submission of electronic sampling data on a Form 43.

Rule 807.

The Commission adopted a new Rule 807, which clarified that Operators must submit and obtain approval of a Form 26, identifying the source of produced water for disposal before commencing injection activities. The Commission also adopted a requirement that operators of both new and existing disposal wells submit a new Form 26 within 90 days of changing a source of produced water to ensure that the Commission has accurate records about the characteristics and origin of all produced water that is injected. The Commission instructs its Staff to issue guidance addressing options for potential bulk filings of Form 26 reports, which may include quarterly reporting of changes of source wells for commercial disposal wells and field-wide water management systems.

Rule 808.

The Commission moved prior Rule 316A to Rule 808. The Commission revised the wording of Rules 808.a and 808.b to clarify that the non-produced fluids that are disposed in injection wells are classified as Exploration and Production Waste ("E&P Waste").

In Rule 808.a.(2), the Commission clarified that operators must obtain the Director's approval through a Form 14A, Authorization of Source of Class II Waste for Disposal for the addition of new types of non-produced Class II waste to the injection stream of a UIC facility.

The Commission revised prior Rule 316A by adopting a new Rule 808.a.(3), which provides examples of non-produced fluids. Consistent with the Commission's newly adopted 100 Series definition of "Class II UIC Well," and EPA's definition of a Class II injection well, non-produced water include, among other things, fluids which are brought to the surface in connection with conventional oil and gas drilling or dehydration of produced natural gas. EPA's definition of a Class II fluid is closely analogous to the Commission's definition of E&P Waste. The Commission instructed its Staff to issue guidance about what substances are classified as non-produced water that may be injected into a Class II UIC Well.

In Rule 808.a.(3), and consistent with the 100 Series and EPA definition of a Class II UIC Well, the Commission also clarified that if a fluid is classified as a hazardous waste at the time it is injected, then it is not a type of non-produced water that can be disposed of in a Class II UIC well. Hazardous waste is a Class I fluid under EPA's classification system, and may only be injected in a Class I well, which is directly regulated by EPA.

Some stakeholders raised questions about whether brine from a desalination plant could be injected into a Class II UIC well. While desalination brine may share many characteristics with produced water and other Class II fluids, it does not meet the definition of a Class II fluid, and therefore could only be lawfully injected in another category of injection well, such as a Class I well.

Rule 809.

The Commission moved prior Rule 325.d.(7) to Rule 809. The Commission clarified that simultaneous injection well applications must satisfy the same requirements as other injection well applications under Rules 803, 804, 805, 806, 807, and 808. Because Rule 809 specifies standards for permit applications, it applies to only new wells.

Rule 810.

The Commission moved prior Rule 325.f to Rule 810. The Commission clarified that commercial disposal well applications must satisfy the same requirements as other injection well applications under Rules 803, 804, 805, 806, 807, and 808, in addition to satisfying the financial assurance requirements of Rules 706, 707, and 713. Because Rule 810 specifies standards for permit applications, it applies to only new wells.

The Commission also adopted a new Rule 810.b that commercial disposal well facilities may be required to perform continuous seismic monitoring, and provide data from the monitoring to the Director upon request. The Commission has determined that commercial disposal well facilities may pose risks of induced seismicity, and seismic monitoring is therefore necessary to evaluate and, if necessary, to mitigate those risks.

Consistent with the revisions the Commission made to Rule 810, the Commission revised the prior definition of a Commercial Disposal Well Facility in its 100 Series Definitions. Among other things, the revised 100 Series definition of a Commercial Disposal Well is a well that receives Class II E&P Waste from multiple non-owner operators, which acknowledges that multiple operators may own a single commercial disposal well.

Rule 811.

The Commission moved prior Rule 401, governing enhanced recovery wells, to Rule 811. The Commission moved the components of prior Rule 401 that regulated gas storage to Rule 220. Accordingly, the Commission removed references to storage operations from Rule 811.a

<u>*Rule 811.a*</u>

In Rule 811.a, the Commission clarified that, although enhanced recovery projects must include at least one injection and one production well, the same well may be used for "huff and puff" style cyclic gas injection projects.[5]

Rule 811.b

In Rule 811.b, the Commission expanded and revised prior Rule 401.b's requirements for enhanced recovery well hearing applications to more closely match the relevant requirements for disposal well applications pursuant to Rule 803. Enhanced recovery well applications must satisfy all requirements of Rules 803, 804, 805, 806, 807, and 808, unless otherwise specified in those Rules. However, unlike disposal well applications, which may be administratively approved by the Director and are only reviewed by the Commission if an adversely affect party appeals to the Commission, enhanced recovery applications can only be approved by the Commission through a hearing pursuant to Rule 503.g.(3). Operators may use several hearing exhibits for Form 31 and 33 applications either by reference to the hearing document number or duplicate attachments, including information required by Rules 811.b.(4), (6), & (8)–(11).

Because Rule 811 specifies standards for permit applications, it applies to only new wells.

Many of Rule 811.b's hearing application requirements mirror the requirements for Form 31 – Intent in Rule 803.g, but are specifically adapted for the unique circumstances of enhanced recovery wells. For example, Rules 811.b.(4), 811.b.(6), 811.b.(8), 811.b.(9), 811.b.(10), and 811.b.(11) all reference the unit in which enhanced recovery operations are proposed. Unlike a disposal well, which impacts only the mineral and surface owners with a direct property interest in and above the formation where injection occurs, an enhanced recovery operation has implications for an entire drilling and spacing unit. Accordingly, notifications, maps, and ownership information must be provided for an entire unit. The Commission intends for its Staff to specify in guidance how operators may submit copies of unit agreements as part of a hearing application pursuant to Rule 811.b.(4) if such agreements have already been submitted to the Commission.

Consistent with changes the Commission made to the Form 2 casing and cementing plan in its recent Wellbore Integrity Rulemaking, the Commission revised Rule 811.g.(7) to reflect its intent that the casing and cementing plan required by Rule 811.g.(7) be a grid provided on a Form 33, not an attachment to the form. Casing and cementing plans therefore must comply with the requirements for casing and cementing plans for a Form 2 pursuant to Rule 308.b.(6).

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[5] *See* James J. Sheng, *Optimization of Huff-n-Puff Gas injection in Shale Oil Reservoirs*, 3 Petroleum 431 (2017), www.sciencedirect.com/science/article/pii/S2405656116302541.

Operators may obtain water well permit and construction information required by Rule 811.b.(10) from the Division of Water Resources. As with Rule 803.g.(8), Rule 811.b.(10) applies to all water wells registered with the Division of Water Resources.

Rule 811.c

The Commission moved prior Rule 402 to Rule 811.c. The Commission clarified the language of Rule 811.c to explain that the Commission will issue a notice of hearing at the time an enhanced recovery project application is filed. Because scheduling unitization hearings may require some time, such hearing applications may precede the filing of Form 31 – Intents and Form 33 – Intents.

Rule 811.d

The Commission moved prior Rule 405.c to Rule 811.d, but did not substantively revise the Rule.

APPENDIX B

900 Series – Environmental Impact Prevention

To improve clarity for operators, local governments, and the public, the Commission consolidated all its Rules primarily intended to prevent and remediate environmental impacts into its 900 Series Rules. Under the Commission's prior Rules, provisions related to protecting the environment through management of Exploration and Production Waste ("E&P Waste") were in the 300 and 900 Series. Rules related to preventing pollution were in the 300 Series. And provisions related to preventing air pollution, waste, and odors from venting and flaring natural gas were in the 300, 600, 800, and 900 Series. In addition to consolidating these Rules into a single Series, the Commission also re-ordered its prior Rules related to management of E&P Waste to better reflect the sequential order of the waste management process. Under the revised order, the 900 Series begins with Rules intended to prevent contamination from occurring and ends with Rules addressing cleanup standards for when contamination nevertheless occurs.

Rule 901.

The Commission substantially revised prior Rule 901, which introduced the Commission's E&P Waste management rules. Most concepts described in prior Rule 901 were either duplicative of the Commission's 200 Series general provisions or were better described in more specific Rules.

Specifically, prior Rule 901.a explained that the prior 900 Series Rules applied to E&P Waste management, as defined in C.R.S. § 34-60-103(4.5). However, both the statutory and regulatory definitions of E&P Waste provide an adequate explanation of this definition and no additional regulatory provision is necessary.

Prior Rule 901.b specified that all reports discussed in the 900 Series must be made on the Commission's forms. Because Rules 206.a and 207 provide clear standards for submission of information to the Director and Commission, a separate regulatory standard in the 900 Series is unnecessary.

Prior Rule 901.d discussed alternative compliance methods for remediation requirements. Because Rule 502 allows operators to seek variances from the Commission and applies to all the Commission's Rules, a separate regulatory standard in the 900 Series is unnecessary.

Prior Rules 901.e and 901.f provided standards for identifying sensitive areas and operations in sensitive areas. The sensitive area determination process was necessary to identify pits constructed prior to 1995 that were subject to specific standards pursuant to prior Rule 911. Because the Commission has also removed prior Rule 911 and consolidated its pit standards into a single set of regulations that are applicable statewide in Rules 909 and 910, the sensitive area determination process is no longer necessary.

Rule 901.a

The Commission moved prior Rule 901.c to Rule 901.a and revised the Rule. Prior Rule 901.c granted the Director authority to impose additional requirements, including sampling, analysis, remediation, monitoring, permitting, and establishing points of compliance based upon reasonable cause to believe that an operator was performing an act which threatened to cause a violation of the standards in prior Table 910-1 or a water quality standard promulgated by the WQCC. Consistent with Senate Bill 19-181's changes to the Commission's statutory authority and mission, *see* C.R.S. § 34-60-106(2.5)(a), the Commission expanded prior Rule 901.c to cover impacts to additional environmental media and a broader range of responsive actions by operators. Specifically, rather than limiting the Director's response to a violation of Table 915-1's soil and groundwater remediation standards and WQCC standards, the Commission authorized the Director to act in response to any impact or threatened impact to public health, safety, welfare, the environment, or wildlife resources. This broader authority is more consistent with the Commission's statutory authority under Senate Bill 19-181, C.R.S. § 34-60-106(2.5)(a), and will allow the Director to require operators to respond to imminent threats to environmental media beyond soil and groundwater, such as impacts to public health, air, surface waters, and wildlife. The Commission also removed unnecessary language regarding an operator performing or having performed an act or practice, and used the simpler verbs "impacting or threatening to impact." Finally, consistent with Senate Bill 19-181's recognition of the mitigation hierarchy, the Commission replaced the term "prevent" with "avoid, minimize, or mitigate." *See* C.R.S. § 34-60-103(5.5)(a)–(b).

Rule 901.a.(1)

In Rule 901.a.(1), the Commission consolidated the lengthy list of potential responses that the Director could require under prior Rule 901.c into a clearer, broader standard: suspending operations or initiating immediate mitigation measures until the cause of the threat or potential threat is corrected. Prior Rule 901.c provided a fairly comprehensive list of potential responses that the Director could require an operator to take to remedy impacts to environmental media. However, the Commission determined that using the catch-all term "initiating mitigation measures" will provide the Director with the flexibility necessary to respond to a wide range of potential circumstances that could arise in the future and are difficult to predict. Additionally, questions have arisen in the past about whether the Director could require an operator to suspend some or all operations at a location in order to respond to an imminent threat to public health or the environment. Consistent with Senate Bill 19-181, C.R.S. § 34-60-106(2.5)(a), the Commission clarified that it does intend to delegate its authority to require operators to temporarily suspend operations at a location until the cause of threats or potential threats are corrected.

Rule 901.a.(2)

Although a Form 27, Site Investigation and Remediation Workplan will not be required for every action under Rule 901.a, many of the response actions listed in prior Rule 901.c, such as remediation, monitoring, permitting, and the establishment of points of compliance are typically addressed by an operator submitting a Form 27. If the Director determines that investigation of a potential risk to public health, safety, welfare, the environment, or wildlife resources is necessary, or remediation, monitoring, permitting, or the establishment of points of compliance is required, the appropriate form for documenting and describing the scope of the required action is a Form 27. Accordingly, in Rule 901.a.(2), the Commission clarified that if the Director requires an operator to conduct such an investigation, the operator must submit a Form 27.

Rule 901.a.(3)

Finally, prior Rule 901.c specified that any action the Director took pursuant to the Rule must comply with the 500 Series Rules. To provide additional specificity about the procedural due process rights afforded to operators under Rule 901.a, the Commission expanded this prior requirement into a more detailed procedure in Rule 901.a.(3). The standard in Rule 901.a.(3) matches the standard in Rule 209.b, which similarly provides procedures for operators to file an expedited appeal and specifies that operators may appeal the Director's decision to the Commission by submitting a hearing application pursuant to Rule 503.g.(10). To provide a more expedited hearing process, the Commission also specified that unlike most hearing matters, the matter will not be assigned to an Administrative Law Judge or Hearing Officer, and must be heard at the Commission's next regularly scheduled meeting. Because Senate Bill 19-181 provides for full-time Commissioners, C.R.S. § 34-60-104.3, it is likely that the Commission's next regularly scheduled hearing will occur much sooner than a matter could be addressed by an Administrative Law Judge or Hearing Officer. Expediting the appeal process by removing an intermediate appellate step also ensures that operators may receive a final decision from the agency sooner if they choose to appeal the Director's decision. The expedited appeal process is particularly important because Rule 901.a.(3) requires operators to continue complying with the Director's order pursuant to Rule 901.a until the Commission makes a decision on the appeal. Rule 512 contemplates that the Commission may receive public comment on any matter that it will hear, and members of the public may therefore submit a comment to the Commission about an expedited hearing pursuant to Rule 901.a.(3).

Some stakeholders suggested that the transition to the full-time Commission makes it unnecessary to provide the Director with discretion to require operators to address immediate threats to public health, safety, welfare, the environment, and wildlife resources in Rule 901.a. However, although the Commission anticipates that it will meet frequently, the time required for a quorum of at least five individual

Commissioners, Staff, and impacted parties to assemble and undergo formal hearing procedures may in some cases be too long to allow an ongoing threat to public health, the environment, or wildlife resources to continue. For example, a sudden well control issue, spill, leak, fire, or other impact could occur overnight or during a weekend, and it may be necessary for the Director to require an operator to take action prior to the full Commission being able to assemble. The Commission believes it struck the balance appropriate for its full-time status by authorizing the Director to require immediate action pursuant to 901.a, but affording operators an expedited hearing process in Rule 901.a.(3).

The Commission did not change prior Rule 901.c's "reasonable cause" standard for the Director's action. The Commission determined that the "reasonable cause" standard has afforded operators sufficient due process under its existing Rules, and that it is consistent with the Commission's statutory authority. Reasonable cause requires, at least, evidence of the alleged violation, as verified by the Director. Rule 523.a acknowledges that the Director may rely upon a complaint to find reasonable cause of an alleged violation. In Rule 901.a.(3), the Commission also clarified that the "reasonable cause" standard in prior 901.c is the standard of review the Commission will apply in appeals. Some stakeholders suggested that the Commission adopt a higher standard of proof than was provided in prior Rule 901.c, such as "substantial evidence." The Commission did not adopt these stakeholders' suggestion, because the "reasonable cause" standard matches the related but distinct statutory standard for rule violations, C.R.S. § 34-60-121(4), and the Commission has successfully implemented prior Rule 901.c's "reasonable cause" standard for decades without issue. Additionally, the Commission determined that adopting a higher evidentiary standard for the Director to meet would not be consistent with Senate Bill 19-181's clear directive that the Commission protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Because the cause of an imminent threat to public health or the environment may not always be simple to conclusively identify during a short timeframe, especially if the potential impact is to a subsurface resource such as groundwater, imposing a higher evidentiary standard would unnecessarily constrain the Director and Commission's ability to respond to imminent environmental threats.

Several stakeholders also questioned whether Rule 901.a is consistent with C.R.S. § 34-60-121(4). This statutory provision governs the Commission and Director's authority to enforce violations of its Rules. By contrast, Rule 901.a provides the Director and Commission with tools to address imminent threats to public health, safety, welfare, the environment, and wildlife resources that may not violate the Commission's Rules. For example, a suspected well integrity issue might not result in a documented violation of the cleanup concentrations in Table 915-1, but it might require additional investigation. The Act clearly confers authority to the Commission to address such imminent threats by directing that "the commission shall regulate operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources." C.R.S. § 34-60-106(2.5)(a). To fulfill this statutory mandate, the Commission must have the ability to address immediate threats to the enumerated resources—this is implicit in the terms "protect and minimize adverse impacts." *See also id.* § 34-60-103(5.5) (defining "Minimize adverse impacts," to include, among other things, "mitigat[ing] the extent and severity of those impacts that cannot be avoided"). Certainly, it is possible that the Director or Commission may later identify a rule violation associated with an operator's action that caused the immediate threat to public health, safety, welfare, the environment, or wildlife resources. Rule 901.a would not prevent the Director from initiating enforcement action for such a Rule violation pursuant to C.R.S. § 34-60-121 and Rule 523. The purpose of Rule 901.a is to provide the Director and Commission with the tools necessary to fulfill the Commission's statutory obligation to remediate imminent threats to public health, safety, welfare, the environment, and wildlife resources, not to provide an end-run around the Commission's ordinary enforcement process.

Some stakeholders also questioned whether Rule 901.a provides too much discretion to the Director, while others argued that Rule 901.a does not provide the Director with sufficient authority to address imminent threats to public health, safety, welfare, the environment, and wildlife resources. The Commission believes that it has delegated an appropriate degree of discretion to the Director in Rule 901.a. The Act provides that the Commission may not make any orders without a hearing. C.R.S. § 34-60-108. Rule 901.a.(3) provides for a direct, expedited appeal to the Commission itself any time that the Director requires an operator to take action pursuant to Rule 901.a, which ensures swift and direct Commission oversight over the Director's decision. Additionally, the Act delineates the Director's powers in C.R.S. § 34-60-104.5. Among other things, the Act authorizes the Director to administer the Act, enforce the Commission's Rules, and implement the Commission's orders. C.R.S. § 34-60-104.5(2). In adopting Rule 901.a, the Commission determined that it was appropriate to delegate its statutory authority to ensure compliance with the Act to the Director by allowing the Director to require operators to take immediate action to prevent, mitigate, and remediate immediate threats to public health. *See* C.R.S. §§ 34-60-106(2.5)(a), (10). Because the Act expressly contemplates that the Commission will delegate implementation powers to the Director, C.R.S. § 34-60-104.5(2), this is a permissible delegation. *See Kobach v. U.S. Election Assistance Comm'n*, 772 F.3d 1183, 1190 (10th Cir. 2014); *Manka v. Tipton*, 805 P.2d 1203, 1205–06 (Colo. App. 1991). The Commission provided reasonable constraints on the authority delegated to the Director by: 1) specifying the "reasonable cause" standard of proof; 2) limiting the situations where the Director can require an operator to take action to situations where the operator has taken an action that is "impacting or threatening to impact public health, safety, welfare, the environment, or wildlife resources;" and 3) specifying the types of response actions the Director can require an operator to take—"suspending operations or initiating immediate mitigation measures" and submitting a Form 27. *See, e.g., Fremont Re-1*

Sch. Dist. v. Jacobs, 737 P.2d 816, 818–19 (Colo. 1987); *Colo. Motor Vehicle Licensing Bd. v. Northglenn Dodge, Inc.*, 972 P.2d 707, 713 (Colo. App. 1998).

Stakeholders also questioned whether providing the Director discretion under Rule 901.a could lead to the appearance of bias or favoritism. The Commission does not share this concern because nothing in Rule 901.a would allow the Director discretion to single individual operators out for different treatment than other operators. Rule 901.a constrains the Director's authority to address situations where an operator's actions are "impacting or threatening to impact" public health, safety, welfare, the environment, and wildlife resources. This reasonable constraint on the Director's authority limits the Director's actions to only situations where there is reasonable cause—in other words—an objective reason—to determine that there is an immediate threat to public health, safety, welfare, the environment, and wildlife resources.

The Commission takes seriously its constitutional and statutory obligation to afford due process to all parties appearing before it, and Rule 901.a provides all parties with due process. Operators may challenge the Director's decision at a Commission hearing, and no action ordered by the Director will become final until it is approved by the Commission after a hearing or unless the operator chooses not to appeal the Director's decision. This process complies not only with the requirements of the Act in Sections 34-60-108 and 121, but also with Section 24-4-104 of the Administrative Procedure Act ("APA"). The concerns raised—the "reasonable cause" standard, the adequacy of the appellate process, that the Director could require an operator to take action without formally finding that the operator violated a Rule, and the Director's discretion—all apply with equal force to prior Rule 901.c. The Commission is unaware of, and no party has raised in the course of this rulemaking, any due process concerns that have arisen during the 23 years since it adopted prior Rule 901.c. Moreover, in Rule 901.a.(3), the Commission afforded clearer and more specific procedural rights to operators than were provided by prior Rule 901.c, which simply instructed that the Director's actions must "comply with the provisions of . . . the 500 Series rules." Finally, Senate Bill 19-181 provides the Commission with even clearer statutory authority to require operators to take action to minimize and mitigate immediate threats to public health, safety, welfare, the environment, and wildlife resources, C.R.S. § 34-60-106(2.5)(a), than existed in 1997, when the Commission adopted prior Rule 901.c (which was Rule 901.e at the time it was adopted).

<u>*Rule 901.b*</u>

In Rule 901.b, the Commission adopted a new rule to incorporate by reference several codes, standards, guidelines, and rules of federal agencies, other state agencies, and nationally recognized organizations and associations. Like all Colorado state agencies, the Commission must comply with the APA, which requires several specific standards for agency rules that incorporate part or all of a code, standard, guideline or rule adopted by another agency or nationally-recognized organization or association. C.R.S. § 24-4-103(12.5). Consistent with Rule 201.g, the Commission's standard practice is to provide all information relevant to the incorporation by reference in the text of the specific Rule where the material is incorporated. *See, e.g.,* 100 Series definitions of Classified Water Supply Segment, Crude Oil Transfer Line, Disproportionately Impacted Community, Gathering Line, & Public Water System and Rules 408.e.(2).C, 411.b.(1).C, 429, 430, 436.d.(2), 602.g.(2), 603.c.(3) & (9), 603.k, 603.o.(6), 608.a, 608.b.(8), 608.d, 609.b, 609.d, 610.b, 610.e, 610.i, 610.k, 610.q, 612.b.(1), 612.d.(2), 612.f.(3).B, 801.a, 801.b, 1102.b, 1102.d.(2) & (3), 1102.g.(2), 1102.l.(2), 1104.h.(1), and 1104.i.(4). However, some incorporations by reference appear numerous times in the 900 Series Rules. For example, WQCC Regulation 41 is incorporated by reference in 23 different 900 Series Rule subsections. Accordingly, the Commission determined that it would be less confusing and clearer to all stakeholders to provide all information relevant to the incorporations by reference in the entire 900 Series Rules in a single Rule 901.b. Although the incorporations by reference in 901.b appear in a single Rule, they are no different than the incorporations by reference that appear elsewhere in the Commission's Rules.

Some stakeholders raised questions about Rule 901.b.(2), which explains that only the current version of the code, standard, guideline, or rule incorporated applies. This statement is necessary to comply with the APA, which requires all incorporations by reference to "state[] that the rule does not include any later amendments or editions of the code, standard, guideline, or rule." C.R.S. § 24-4-103(12.5)(a)(II). The Commission recognizes that some of the regulations and codes it incorporates by reference may change over time. However, it is subject to the same constraints as all Colorado state agencies, and may only permissibly incorporate the current version of a regulation or code. The Commission expects that because Senate Bill 19-181 creates a full-time Commission, C.R.S. § 34-60-104.3, it will be more feasible to conduct rulemakings to periodically update changes to incorporated materials.

Additionally, some stakeholders raised questions about the incorporation of the State Engineer's Water Well Construction and Permitting Rules in Rule 901.b.(3).E. These regulations were incorporated by reference in prior Rule 908.b.(9).B.i. Therefore, in Rule 901.b.(3).E, the Commission merely provided the full citation required by the APA. C.R.S. § 24-4-103(12.5).

Some stakeholders raised concerns that by incorporating other agencies' standards by reference, the Commission intends to take enforcement action for violation of those agencies' regulations that are not also violations of the Commission's Rules. The Commission will not take enforcement action solely for a violation of Rule 901.b. Rather, the Commission will take enforcement action if an operator violates another Commission Rule, where the other agency's regulations are incorporated by reference. For example, Rule 907.b.(9).B.ii requires that monitoring wells be constructed for purposes of monitoring groundwater quality at a centralized E&P waste management facility according to the State Engineer's Water Well

Construction and Permitting Rules, which are incorporated by reference in Rule 901.b. The Commission could thus take enforcement action for a violation of Rule 907.b.(9).B.ii if the operator constructing a monitoring well at a centralized E&P waste management facility did not adhere to the specific standards for monitoring well construction found in the State Engineer's Water Well Construction and Permitting Rules. Improper construction could lead to collection of inaccurate data and an improperly constructed monitoring well could act as a conduit for contaminants to reach groundwater. However, the fact that the State Engineer's Water Well Construction and Permitting Rules are incorporated by reference in Rule 901.b does not give the Commission general authority to enforce those rules in other contexts unrelated to oil and gas operations. For example, the Commission does not have authority to take enforcement action for improper construction of a domestic water well that is not associated with oil and gas operations.

Rule 902.

The Commission moved portions of prior Rule 324A to Rule 902. As noted above, the Commission moved prior Rule 324A.d, governing injections into underground sources of drinking water, to Rule 801 and its 100 Series Rules, consistent with the Commission consolidating all its Rules related to injection wells into its 800 Series Rules.

The Commission adopted a new Rule 902.a, specifying that operators will prevent Pollution. The Commission added this new standard in concert with revising the 100 Series definition of "Pollution." The Commission changed the definition of "Pollution" in two ways. First, to avoid the use of gendered language in its Rules, the Commission changed the words "man-made or man-induced" to "anthropogenic." The Commission does not intend for the term "anthropogenic" to have a different meaning than the language in its prior definition of Pollution. Second, the Commission added the clause "that is not authorized or allowed by the Commission's Rules or applicable regulations promulgated by another federal, state, or Local Government agency." This added clause refines the definition to exclude contamination and degradation of air, water, soil, and biological resources that is expressly authorized or allowed by the Commission or another regulatory agency. The term "authorized" pollution is intended to address, for example, release of an air pollutant from a facility with an air pollution permit issued by the APCD at a level below the emissions limit set in the facility's permit for that pollutant. The Commission does not intend for the term "allowed" pollution to be misinterpreted as release of a pollutant that is not addressed by an agency's rules or a permit but is expressly allowed within the context of those rules. For example, the AQCC's rules for controlling flash gas emissions from storage tanks expressly allow those emissions to be uncontrolled from atmospheric condensate storage tanks under common ownership with less than two tons per year actual uncontrolled emissions of volatile organic compounds, because they only apply to storage tanks under common ownership with emissions greater than or equal to two tons per year. *See* 5 C.C.R. § 1001-9:D.I.B.29.

Consistent with this revision to the 100 Series definition of "Pollution," the Commission required in Rule 902.a that operators prevent pollution. This standard implements the Commission's statutory directive to "protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5)(a); *see also id.* § 34-60-106(1)(c) (directing the Commission to require the drilling of seismic holes and wells in a manner that "prevent[s] . . . the pollution of fresh water supplies by oil, gas, salt water, or brackish water"). Although many specific forms of pollution are specifically addressed by the Commission's Rules, the Commission's decades of experience with enforcing prior Rule 324A have confirmed the importance of having an enforceable regulatory standard to address forms of pollution that are forbidden by the Act but not otherwise addressed in the Commission's Rules.

Rule 902.a

The Commission intentionally worded Rule 902.a to state that "Operators will prevent Pollution" rather than stating that "Operators will not Pollute." The verb "prevent" indicates taking affirmative actions to avoid pollution from occurring, such as maintaining equipment in good working order so that unintentional leaks, spills, and releases are less likely to occur. By contrast, the verb "will not" is a categorical statement that would make it a violation of the Commission's Rules if any contaminant originating from an operation entered the air, water, or soil. The Act requires the Commission to "minimize adverse impacts" to public health, safety, welfare, the environment, and wildlife resources, C.R.S. § 34-60-106(2.5)(a), and in turn defines "Minimize adverse impacts" to mean, among other things, "to the extent necessary and reasonable . . . to avoid adverse impacts from oil and gas operations," C.R.S. § 34-60-103(5.5)(a). Rule 902.a implements this statutory standard by instructing operators to "prevent" pollution, which is analogous to "avoid[ing]" it. Moreover, like all the Commission's Rules intended to implement statutory language that includes the term "Minimize adverse impacts," Rule 902.a is constrained by the statutory definition including the terms "to the extent necessary and reasonable." C.R.S. § 34-60-103(5.5).

Rule 902.b

The Commission moved portions of prior Rule 324A.a to Rule 902.b. The Commission revised Rule 902.b by making its language align almost exactly with C.R.S. § 34-60-106(2.5)(a). Prior Rule 324A.a tracked the language of the Act's prior definition of "minimize adverse impacts," which was revised by Senate Bill 19-181. *Compare* C.R.S. § 34-60-103(5.5) (2018) *with id.* § 34-60-103(5.5) (2020). Thus, Rule 902.b provides necessary updates to the Commission's Rules to meet the revised statutory requirements of Senate Bill 19-181, and specifically fulfills the Commission's obligation to "regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources and shall protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5)(a).

Some stakeholders argued that Rule 902.b is unachievable, because any action can have an environmental impact. The Commission does not agree with these stakeholders. The Commission's and Director's discretion to enforce Rule 902.b is reasonably bounded by the statutory definition of "minimize adverse impacts," which incorporates the terms "necessary and reasonable." C.R.S. § 34-60-103(5.5). The Commission does not believe it would be reasonable for the Director or Commission to pursue an enforcement against an operator for a lawful, permitted activity that is conducted pursuant to the Commission's Rules and does not result in unauthorized pollution. For example, the Commission recognizes that other agencies, such as the Air Quality Control Commission ("AQCC"), allow operators to use certain types of equipment at oil and gas locations, such as pneumatic devices, that are designed to emit limited quantities of natural gas into the atmosphere. Although this emission could have an adverse impact on air resources, the Commission would not enforce Rule 902.b against the operator so long as the operator complied with the AQCC's regulations governing permissible emissions from pneumatic devices.

Rule 902.c

The Commission moved portions of prior Rule 324A.a governing unauthorized discharge of certain materials to Rule 903.c, but did not substantively revise the Rule. The Commission determined that separating the broader standard of Rule 902.b from the narrower prohibitions in Rule 903.c would provide better clarity to operators and would facilitate simpler resolution to enforcement actions.

Rule 902.d

The Commission moved prior Rule 324A.b to Rule 902.d. As it did throughout its Rules, the Commission capitalized defined terms, changed the word "shall" to "will," and updated cross-references to its revised Rules. To remove ambiguity, and consistent with Rule 901.a, the Commission simplified the clause "perform any act or practice which violates" to instead use the verb "violate." To similarly improve clarity, the Commission also revised the clause "shall constitute a violation of water quality standards" to instead say "violate numeric or narrative water quality standards" to specify more clearly which WQCC standards were being referenced. In its experience with implementing prior Rule 324A.b, the Commission learned that some operators were unaware of the WQCC's narrative water quality standards, and accordingly in Rule 902.d the Commission sought to eliminate that confusion by specifically referencing them.

Numerous stakeholders raised questions about Rule 902.d. Specifically, some stakeholders questioned whether the Commission has authority to enforce violations of other agency's regulations. Although the primary intent of Rule 902.d is to remind operators of their obligations to comply with other agencies' regulations, nothing prohibits the Commission from enforcing violations of its own Rules, consistent with its statutory authority, including components of its own Rules that incorporate other agencies' regulations by reference. Other stakeholders suggested that the Commission make establishing points of compliance mandatory by changing the term "may" to "will." The Commission did not agree with these stakeholders, because establishing points of compliance is a specific process governed by Rules 907.b.(9).B and 914 that does not apply in every event of pollution.

Rule 902.e

The Commission moved prior Rule 324A.c to Rule 902.e, but did not make any substantive changes to the Rule other than the same changes to improve clarity discussed above in Rule 902.d. As with Rule 902.d, some stakeholders questioned the Commission's authority to enact the Rule, but the Commission believes that Rule 902.e is well within its statutory authority for the reasons expressed above.

Rule 902.f

The Commission moved prior Rule 324A.e to Rule 902.f, but did not make any substantive changes to the Rule. As with Rules 902.d and 902.e, although the Commission did not make substantive revisions to Rule 902.f, numerous stakeholders raised questions about it. As discussed above, the Commission believes that Rule 902.f is well within its statutory authority. Additionally, the Commission acknowledges that the practices of counties may vary with respect to certificates of designation, but this does not change an operator's obligation to obtain a certificate of designation when the operator is required to do so by state law or local ordinance. Other stakeholders questioned whether certain kinds of waste generated by oil and gas operations would qualify as "solid waste" under CDPHE regulations. The Commission did not change the language of Rule 902.f, because CDPHE regulations define "solid waste" to include "solid, liquid, semisolid, or contained gaseous material." 6 C.C.R. § 1007-2:1–1.2.

Rule 903.

The Commission consolidated portions of prior Rules 317.p, 604.c.(2).C, 606A, 606B, 805.b, and 912 into a single Rule 903. Consolidating all the Rules governing venting and flaring natural gas into a single Rule will significantly improve clarity for operators, local governments, the public, the Commission's Staff, and other state and federal regulatory agencies.

The Commission recognizes that venting and flaring natural gas is a waste prohibited by the Act, § 34-60-107, C.R.S., and also poses safety and environmental risks. The Commission therefore prohibited venting and flaring, except as specifically allowed pursuant to Rule 903. The Commission encourages operators to use current, effective technology to capture natural gas during all phases of oil and gas operations. In situations where Rule 903 allows an operator not to capture natural gas, the Commission intends for operators to flare, rather than vent that natural gas, unless Rule 903 specifically allows the operator to vent the natural gas.

The presence of Rules relating to venting and flaring natural gas in such a wide array of the Commission's prior Rules underscores the unique nature of venting and flaring with respect to the Commission's statutory authority. The Commission has statutory authority to regulate the venting and flaring of natural gas for many different reasons. Its prior and current Rules therefore regulate venting and flaring for many different purposes.

First, the Commission has authority to regulate venting and flaring because they are each an integral component of oil and gas production operations, and the Commission has broad statutory authority over such operations. C.R.S. §§ 34-60-105(1)(a) ("The commission has jurisdiction over all persons and property, public and private, necessary to enforce this article 60"); 34-60-106(2)(a) (authorizing the Commission to regulate "drilling, producing, and plugging of wells and *all other operations for the production of oil or gas*" (emphasis added)); *see also id.* § 34-60-103(6.5) (defining "Oil and gas operations").

Second, the Commission has specific authority to regulate safety risks posed by both venting and flaring because of the potential for unintentional combustion of vented natural gas, and fires caused by improper flaring of natural gas. *See* C.R.S. §§ 34-60-102(1)(a)(I), 34-60-103(5.5)(a), 34-60-106(2.5)(a), (10).

Third, the Commission has authority to regulate odors caused by venting and other emissions of natural gas, consistent with its statutory authority to protect public welfare. *See* C.R.S. §§ 34-60-102(1)(a)(I), 34-60-103(5.5)(a), 34-60-106(2.5)(a), (10).

Fourth, the Commission has authority to regulate venting and flaring natural gas because of the public health impacts of emitting natural gas into the air and combusting it on site. *See* C.R.S. §§ 34-60-102(1)(a)(I), 34-60-103(5.5)(a), 34-60-106(2.5)(a), (10). Emitting natural gas into the air has several potential public health impacts. First, many of the hydrocarbon constituents of natural gas are directly toxic or harmful to human health because of their carcinogenic, mutagenic, teratogenic, neurotoxic, or other properties, and many are classified by the U.S. Environmental Protection Agency ("EPA") as hazardous air pollutants ("HAPs"). *See generally* 42 U.S.C. § 7412(b)(1). Evidence in the administrative record shows that HAPs emitted by the oil and gas sector, including but not limited to benzene, toluene, ethylbenzene, and xylenes (collectively, "BTEX"), n-hexane, 2,2,4-trimethylpentane, formaldehyde, methanol, ethyltoluenes, isoprene, and trimethylbenzene, have human health impacts based on various durations and concentrations of exposure. Second, many hydrocarbon constituents of natural gas are classified by EPA as volatile organic compounds ("VOC"), which contribute to tropospheric ozone formation. *See* 40 C.F.R. § 51.100(s). Evidence in the administrative record shows that tropospheric ozone harms human health in numerous ways, and above certain concentrations may contribute to respiratory difficulties, increased asthma attacks, cardiovascular disease, and even premature death. Elevated tropospheric ozone concentrations also adversely impact public welfare by inhibiting vegetation and crop growth. The Denver-Boulder-Greeley-Ft. Collins-Loveland area is currently classified as a "serious" nonattainment area for the 2008 75 parts per billion eight-hour National Ambient Air Quality Standards for ozone. 40 C.F.R. § 81.306. Other areas of Colorado with substantial amounts of oil and gas activity, including Rio Blanco County, have also registered elevated ozone levels during recent years. Third, the primary constituent of natural gas is methane, which contributes to climate change because it is a greenhouse gas that has approximately 87 times the global warming potential of carbon dioxide over a 20-year period. Climate change is projected to have numerous potential impacts on public health and welfare in Colorado. Finally, flaring natural gas may also impact public health by causing emissions of nitrogen oxides ("NOx") and particulate matter ("PM"). Like VOCs, NOx contributes to tropospheric ozone formation, which may impact public health. PM, especially fine particulate matter formed by combustion, has numerous direct impacts on human health in high concentrations. And both NOx and PM harm public welfare by reducing visibility.

Fifth, the Commission has authority to regulate venting and flaring of natural gas because they constitute waste of natural gas. C.R.S. §§ 34-60-103(11)–(13); 34-60-107; *see also id.* §§ 34-60-102(1)(a)(II) (legislative declaration directing the Commission to "[p]rotect the public and private interests against waste in the production and utilization of oil and gas"); 34-60-106(3)(a) (authorizing the Commission to limit production of oil or gas "for the prevention of waste"); 34-60-117(1) ("The commission has authority to prevent waste[.]"). Both before and after Senate Bill 19-181 was adopted, the Act defined "waste" to include venting and flaring. The Act defines "waste" of gas to "include[] the escape, blowing, or releasing, directly or indirectly into the open air, of gas from wells productive of gas only, or gas in an excessive or unreasonable amount from wells producing oil or both oil and gas." C.R.S. § 34-60-103(11)(a). Thus, for wells that produce only natural gas, any escape or release of natural gas into the air—in other words, venting—constitutes waste, and for wells that produce oil or both oil and natural gas, any excessive or unreasonable venting constitutes waste. The Act further provides that for both oil and natural gas wells, waste also means "[p]hysical waste, as that term is generally understood in the oil and gas industry." C.R.S. § 34-60-103(13)(a)(I). Physical waste is now and has long been understood in the oil and gas industry to include the direct release of natural gas into the air, and combustion of natural gas on location without putting it to productive use. *See* Wm. & Meyers, *Manual of Oil and Gas Terms* 1046 (14th ed. 2009) (describing "physical waste" as "the loss of oil or gas that could have been recovered or put to use," including "flaring of gas"); *see also, e.g.*, J. Howard Marshall & Norman L. Meyers, *Legal Planning of Petroleum Production: Two Years of Proration*, 42 Yale L.J. 702, 713 n.31 (1933) (discussing 1929 Texas statute that defined physical waste to include "escape into the open air of natural gas," and early efforts by courts to resolve questions of state authority to regulate economic waste in addition to physical waste); *Cities Serv. Gas Co. v. Peerless Oil & Gas Co.*, 340 U.S. 179, 185 (1950) ("It is now undeniable that a state may adopt reasonable regulations to prevent economic and physical waste of natural gas."); *R.R. Comm'n v. Shell Oil Co.*, 154 S.W.2d 507, 509 (Tex. Civ. App. 1941) (describing permissible regulation to prevent physical waste as including excess aboveground storage of oil or gas in open air tank). Finally, the Act defines waste to include "drilling, equipping, operating, or producing of any oil or gas well or wells in a manner that causes or tends to cause . . . unnecessary or excessive surface loss or destruction of oil or gas." C.R.S. § 34-60-103(13)(a)(II). Surface loss is an express reference to venting: natural gas that is lost into the air at the surface. Surface destruction is an express reference to flaring: natural gas that is brought to the surface and destroyed through combustion. In Senate Bill 19-181, the General Assembly did not substantively revise any of these definitions, but did clarify that waste "[d]oes not include the nonproduction of gas from a formation if necessary to protect public health, safety, and welfare, the environment, or wildlife resources as determined by the commission." C.R.S. § 34-60-103(11)(b); *see also id.* §§ 34-60-103(12)(b) (same with respect to oil), (13)(b) (same with respect to both oil and gas). The General Assembly included such a detailed and comprehensive definition of waste in the Act because the Act includes a firm, unequivocal statement that "[t]he waste of oil and gas in the state of Colorado is prohibited by this article." C.R.S. § 34-60-107.

For these five independent reasons, the Commission determined that it has legal authority under the Act to regulate the venting and flaring of natural gas associated with oil and gas operations. The Commission adopted Rule 903 consistent with its statutory authority, and to implement its statutory obligation to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and to prevent waste. Consistent with C.R.S. § 34-60-103(11)(a), the Commission determined that all venting and flaring of natural gas from wells that produce only natural gas constitutes waste. And for wells that produce both oil and natural gas, the Commission determined that venting and flaring natural gas in a manner prohibited by Rule 903 is excessive and unreasonable pursuant to C.R.S. § 34-60-103(11)(a), and causes unnecessary or excessive surface loss pursuant to C.R.S. § 34-60-103(13)(a)(II). This is consistent with the Commission's prior interpretation of its obligation to prevent waste, as prior Rule 912.a provided that "[t]he unnecessary or excessive venting or flaring of natural gas produced from a well is prohibited." Additionally, prior Rule 323 prohibited open pit storage of oil and other hydrocarbon substances, explaining that this practice "is considered to be waste." In addition to being consistent with the Commission's prior interpretation of its statutory authority, the Commission's interpretation of its statutory authority is also consistent with Senate Bill 19-181's changes to the definition of waste. If an operator must curtail production of oil or natural gas to comply with Rule 903 (for example for failure to comply with a gas capture plan pursuant to Rule 903.e.(3)), that does not constitute waste pursuant to C.R.S. §§ 34-60-103(11)(b), (12)(b), & (13)(b).

The statutory authority of the AQCC to regulate air emissions from oil and gas operations does not diminish the Commission's authority to regulate venting and flaring to prevent waste and protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The U.S. Supreme Court has recognized that when two agencies each have independent statutory mandates to regulate the same activity, both agencies may permissibly regulate the activity. *Massachusetts v. EPA*, 549 U.S. 497, 532 (2007) ("The two obligations may overlap, but there is no reason to think the two agencies cannot both administer their obligations and yet avoid inconsistency."). Unless the General Assembly makes explicit that one agency has exclusive jurisdiction in a regulatory sphere, the regulations of one state agency cannot preempt the regulations of another. *See, e.g.*, C.R.S. § 25-8-202(7)(a) (making the WQCC "solely responsible" for adopting water quality standards and classifying state waters, and specifying bounds of other agencies' authority, including the Commission, to implement those standards). The General Assembly did the exact opposite of this with Senate Bill 19-181: it explicitly affirmed that both the Commission and the AQCC have statutory authority to regulate venting and flaring from oil and gas operations. C.R.S. §§ 25-7-109(10)(c) ("[N]othwithstanding the grant of authority to the oil and gas conservation commission in article 60 of title 34, including specifically section 34-60-105(1), the [air quality control] commission may regulate air pollution from oil and gas facilities . . . including during pre-production activities, drilling, and completion."); 34-60-105(1)(b)(I) (recognizing "the authority of [t]he air quality control commission to regulate, pursuant to article 7 of title 25, the emission of air pollutants from oil and gas operations").

Although the Commission has the authority to regulate activities that are also regulated by the AQCC, in the 800/900/1200 Mission Change Rulemaking, the Commission made numerous efforts to ensure that its regulations align with the AQCC to improve efficiency for state agencies and clarity for operators and the general public. The Commission's Staff partnered closely with Staff from the APCD to ensure that the two agencies' regulations aligned through frequent communication and numerous meetings. Additionally, the Commission eliminated several of its prior Rules, such as prior Rules 805.b.(2).A, B, & D that were duplicative of AQCC regulations. In other cases where it is important for both agencies to have independent enforcement authority, the Commission revised its prior Rules, such as prior Rule 805.b.(3), to better align with parallel AQCC regulations. Finally, the Commission carefully drafted and revised regulatory definitions in its 100 Series Rules and applicable standards under Rule 903 to avoid duplication with and potential conflicts with AQCC regulations. All of these efforts ensure that state enforcement resources are used efficiently and that both agencies' regulations will function well in concert, which provides clarity, certainty, and efficiency for operators, local governments, and the public. However, the Commission does not intend for its efforts to promote efficiency and clarity by aligning its Rules more clearly with the AQCC's regulations to in any way diminish the Commission's authority to regulate venting and flaring of natural gas.

Consistent with its efforts to promote efficiency and align its Rules with the AQCC's regulations, the Commission did not adopt regulatory standards related to air quality monitoring that appeared in the initial "Straw Dog" draft of Rule 903 that was released for stakeholder feedback in February 2020. Based on consultation between the Commission's Staff and the APCD, the Commission's Staff determined that it was a more efficient use of limited state resources for the AQCC to adopt regulations related to on-site monitoring at oil and gas locations, because APCD staff typically have greater expertise and experience with reviewing air quality monitoring plans and interpreting air quality monitoring data. Additionally, in September 2020, the AQCC adopted regulations related to on-site monitoring at oil and gas locations. However, the Commission's decision to forego adopting specific regulatory standards for air quality monitoring at oil and gas locations does not in any way preclude the Commission from requiring air quality monitoring at oil and gas locations on a case-by-case basis, where necessary and reasonable to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. For example, the Commission may require air quality monitoring pursuant to Rule 209.a, or pursuant to Rule 307.b.(1) as a condition of approval on an oil and gas development plan where proximity to sensitive receptors indicates a unique need for specific data about whether air emissions may be impacting public health.

100-Series Definitions Related to Rule 903

Flaring

In its 100 Series Rules, the Commission defined two terms used in Rule 903: Venting and Flaring. The Commission intentionally used the term "natural gas" in the definitions of Flaring and Venting to clarify that the requirements for Flaring and Venting apply to produced gas, and do not apply to hydrocarbons that normally evaporate or vaporize from liquid hydrocarbons, including flash gas. The Commission adopted a definition of Flaring to distinguish between different forms of combustion that occur at an oil and gas location. The Commission does not intend to regulate all combustion at an oil and gas location as flaring.

The Commission considers the combustion of high-pressure natural gas to be flaring. The Commission intends for operators to utilize current technology, where possible, to capture low-pressure natural gas for beneficial use. If gas capture is not possible, then the Commission intends for that low-pressure natural gas to be combusted.

Consistent with this distinction, the Commission intends to exclude several categories of combustion from its definition of Flaring, and intends for its Staff to issue guidance to specify categories of combustion that are not considered flaring. One exclusion is natural gas that is intentionally used for a beneficial onsite process. These beneficial onsite processes would not clearly meet the definition of waste.

The Commission does not intend for produced natural gas to be routed through a tank and vented or flared from the tank. However, the Commission does intend to exclude combustion that is required by the AQCC for purposes of the control of emissions from tanks. The AQCC has adopted numerous emissions control regulations requiring the use of emission control devices to reduce VOC and methane emissions from tanks. These regulations are found in AQCC Regulation Number 7, Part D, Sections I.D and II. C. *See* 5 C.C.R. § 1001-9:D.I.D & II.C. But, consistent with the Act's statutory prohibition on waste, if an operator directs produced natural gas to a tank to be vented or flared, that waste of natural gas would nevertheless be considered Flaring.

AQCC regulations can also require the use of combustion devices to control natural gas emissions from separation equipment where an operator does not route the gas to a gathering line. *See* AQCC Regulation Number 7, Part D, Section II.F, 5 Colo. Code Regs. § 1001-9:D.II.F. This combustion would fall within the definition of Flaring, because it is the Commission's intent to reduce the instances of Flaring this natural gas.

<u>*Venting*</u>

The Commission defined Venting in its 100 Series Rules as "allowing natural gas to escape into the atmosphere," but provided for a few significant carve-outs for clarity and to avoid duplication with AQCC regulations. The Commission chose to use the verb escape for consistency with the statutory definition of waste, C.R.S. § 34-60-103(11)(a). In earlier drafts of the definition, the Commission's Staff proposed to use the word "intentionally" to differentiate between unintentional leaks and intentional Venting. The AQCC has a distinct set of regulations requiring operators to identify and repair leaks. Because of the protectiveness of the AQCC's leak detection and repair ("LDAR") regulations, the Commission determined that it was unnecessary for its Rules to address LDAR, and sought to avoid confusion that could be engendered from both agencies regulating the same activity. Most leaks are excluded from the definition of Venting due to the component's location at or downstream of the tank. However, some emissions considered leaks by AQCC regulations occur from some of the same equipment where the Commission is seeking to limit Venting, including the separator. Based on input from stakeholders, the Commission determined that it was appropriate to explicitly exclude leaks from the definition of Venting, except for leaks that result from inadequate design of separation equipment—those that could have been prevented if the separation or other equipment was designed to handle the volume of gas flowing through it.

Some stakeholders questioned how the Commission could enforce applications of the definition of Venting because of challenges with identifying and proving intent. Many other Commission Rules explicitly or implicitly require the Director and Commission to identify and prove an operator's intention to take a certain action, and this has not proven to be a barrier to enforcement actions in the past.

Relatedly, in the initial Straw Dog version of Rule 903 that the Commission's Staff released for stakeholder review in February 2020, Staff proposed a draft rule that required operators to submit LDAR reports that they submitted to the APCD upon the Director's request. The Commission ultimately chose not to adopt this requirement because the Commission and Director have authority to request such records pursuant to Rules 206.b.(6) and 207, and it was therefore unnecessary to specify distinct authority to request a certain subcategory of records in Rule 903.

The AQCC also has numerous regulations governing emissions from equipment that are designed to allow some natural gas to escape into the air as part of a process, such as pneumatic devices and pneumatic pumps. Because the escape of natural gas from such a device is part of the intended operation of these devices, emissions from these devices do not fall within the definition of "Venting."

The Commission's Staff received feedback from stakeholders that earlier drafts of the definition of Venting were unclear as to whether the Commission intended to regulate some of the same emissions regulated by the AQCC, such as emissions during gauging and loadout activities, or emissions from access points on tanks. The Commission's intent in regulating Venting is to address the natural gas coming out of the well that should be, or would be sent to a gathering line or otherwise put to beneficial use (or, in limited circumstances, flared), absent the Venting. The Commission does not intend for its definition of Venting to include the gas entrained in the hydrocarbon liquids that is released, or flashed, as the liquids are sent from separation equipment to a tank, or from working and breathing losses. However, the Commission could not exclude all emissions from tanks because tanks may emit some natural gas. Tanks can sometimes act as separation equipment where, for example, there is no separator, or where the separator is not adequately sized to achieve sufficient separation of the entrained natural gas, and some of the natural gas that could or should have been separated from the liquid upstream of the tank is nonetheless routed to the tank. Natural gas that would have been separated if the separation equipment had been appropriately sized is within the scope of the Commission's definition of Venting. Further, natural gas emitted from a tank after being sent to the tank during activities such as well liquids unloading would be included in the definition of Venting. Additional examples of Venting include: opening a bradenhead valve (except where required as part of a bradenhead test pursuant to Rule 419), emissions from a combustion device controlling the separator when the combustion device is not operating properly (for example, there is no pilot light, or the device is offline), and emissions from a tank of natural gas sent to the tank because of a shut-down in a gathering line or other inability to route gas to the gathering line.

Several stakeholders suggested adding a clause to the definition of Venting stating that Venting does not include escape of gas into the atmosphere that is not authorized by the Commission or the AQCC. The Commission did not adopt these stakeholders' suggestion because some authorized releases of gas still qualify as Venting, and the Commission's Rules and the AQCC's regulations each define the situations in which Venting is permissible.

Commencement of Production Operations

The Commission adopted a new definition of Commencement of Production Operations to distinguish between the completion-stage standards in Rule 903.c and the production-stage standards in Rule 903.d. The Commission also used the definition in other Rules adopted and revised during the 200–600 and 800/900/1200 Mission Change Rulemakings, including Rules 423.c.(2).A & d.(2)–(3) and 424.c.(3), d.(1)–(2), & e.

The definition references the date that product consistently flows to a sales line, gathering line, or tank from a well. Staff will evaluate whether natural gas from a well "consistently" flows to a gathering line on a case by case basis. The Commission intends for operators to provide all records necessary, upon request, for its Staff to verify compliance with regulations using the term "Commencement of Production Operations." The Commission anticipates that when 75% to 95% of the total daily volume of natural gas produced is directed to a sales line, the well is "consistently" producing in salable quantities, although the Commission intends for its Staff to evaluate whether flow is "consistent" on a case by case basis.

The Commission's Staff consulted closely with the APCD staff about the appropriate definition. Based on that consultation the Commission chose to adopt a definition that is similar to, but slightly different than, the AQCC's definition of "commencement of operation." *See* 5 C.C.R. § 1001-9:D.I.B.7. The Commission determined that it is appropriate for the two agencies to have different definitions for several reasons. First, the AQCC definition covers more than just oil and gas facilities. Second, the Commencement of Production Operations under the Commission's Rules is relevant to multiple considerations, including royalty payments, production reporting, reclamation standards, noise standards, and lighting standards, none of which are considerations in the AQCC's rules. Accordingly, the Commission determined that it was appropriate for its definition to focus on whether a well is capable of producing separable gas or salable liquid hydrocarbons that flow consistently to a sales line, gathering line, or tank, rather than on the presence of permanent production equipment at a location, which is the standard used in the AQCC definition.

Production frequently commences prior to the end of flowback, and production can and does commence prior to permanent equipment being in place and temporary equipment being removed. The Commission does not intend for the presence of some temporary equipment at a location to mean that production operations have not yet commenced if separable gas or salable liquid hydrocarbons are already being produced and consistently flowing to a sales line, gathering line, or tank. The Commission tailored its definition to provide additional clarity on a frequent question that has arisen in the past as a result of operator confusion about when to designate the date of first production on Form 5A, Completed Interval Reports. The Commission's new definition clarifies when the date of first production occurs and will resolve that question on Form 5As going forward. The Commission recognizes that there are situations where a well may be drilled and completed, but temporarily shut in and not actually producing. The Commission understands that *production* may not yet be occurring at such a well, but because the well is capable of *production operations*, the Commission intends for it to fall within the definition of Commencement of Production Operations. The Commission believes that it has appropriately tailored the use of this defined term to avoid imposing unnecessary or irrelevant burdens on such wells.

<u>Completed Well</u>

Consistent with the new definition of Commencement of Production Operations, the Commission revised its definition of "Completion" to instead define a "Completed Well." The revised definition is simpler and clarifies that a well will be considered completed when oil or gas is produced through the wellhead from the producing interval, and after the production string has been installed. Some stakeholders suggested changing the term "production string" to "tubing." The Commission did not adopt this suggestion because not all operators utilize tubing strings.

<u>Flowback</u>

Also consistent with the new definition of Commencement of Production Operations and the revised definition of Completed Well, the Commission adopted a new definition of Flowback. This definition codifies and clarifies the EPA definitions of initial Flowback stage and separation Flowback stage that the Commission has used for several years in its March 18, 2016 Notice to Operators ("NTO") re: Rule 912.

The Commission chose not to specify when the flowback period begins and ends in the 100 Series Definition of Flowback, because such specification was not necessary given the limited uses of the term in the Commission's 400 Series Rules and Rule 903.c.(2). However, the Commission intends for operators to control separable gas as soon as possible. The Commission recognizes that Flowback is a term that is commonly used in the oil and gas industry, and that the defined term "Flowback" in the Commission's Rules does not necessarily match that definition. The Commission also recognizes that its definition is similar to, but somewhat different from, the AQCC's definition. This is the reason the Commission has provided a definition of the term—because it is a term used in specific contexts in the Commission's Rules, governing only a limited subset of operations, and accordingly the Commission narrowly tailored the definition to match those specific uses in the Commission's Rules.

Upset Condition

Finally, the Commission adopted a new definition of Upset Condition. The Commission also adopted this definition based on close consultation with the APCD's staff. As used in Rule 903, the term Upset Condition refers to sudden and unavoidable circumstances, beyond an operator's control, that result in abnormal operations and require correction. The Commission recognizes that unique standards for venting and flaring may need to apply in such circumstances in order to protect public safety and public health. The Commission intends for its definition of Upset Condition to include sudden unplanned lack of pipeline capacity, which is why the definition includes the term "event."

Some stakeholders asked the Commission to define conditions that do not constitute an Upset Condition. The Commission did not adopt this suggestion, because the Commission did not want to inadvertently omit any categories of activities that would not be considered an Upset Condition from this list, thereby implying that they are, in fact, an Upset Condition. However, the Commission does not consider an operator's negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance to be Upset Conditions.

Productivity Test & Production Evaluation

Consistent with adopting Rule 903.d.(1).C, the Commission also adopted definitions of Productivity Test and Production Evaluation in its 100 Series Rules, which were previously undefined terms. Each term has a distinct meaning, but both refer to tests and evaluations used to determine whether a wildcat or exploratory well is viable and capable of producing economic quantities of oil or gas.

Rule 903.a

The Commission consolidated prior Rules 317.p and 912.e into a single Rule 903.a. Prior Rule 317.p required operators to notify local emergency dispatchers and local governmental designees ("LGDs") prior to flaring when possible, and in all cases within 2 hours of a flaring event. Prior Rule 912.e similarly required prior notice of flaring to local emergency dispatchers and/or LGDs where possible, and in all cases within 2 hours of a flaring event. The Commission eliminated redundancy and confusion by combining these two similar standards into a single Rule 903.a.

Rule 903.a.(1)

In Rule 903.a.(1), the Commission clarified that prior notice should be given to local governments and/or local emergency response authorities as soon as practicable prior to planned flaring events, but no later than two hours before the event. To provide additional clarity and to facilitate easier compliance, in Rule 903.a.(1), the Commission also specified that notice may be verbal, written, or electronic, because prior Rules 317.p and 912.e did not specify a notice mechanism. In Rule 903.a.(2), the Commission specified that only verbal or electronic notice are sufficient, because written notice (*e.g.*, a letter) is a less timely communication mechanism. Consistent with Rule 215, the Commission removed the reference to LGDs in prior Rules 317.p and 912.e, and instead used the term "Local Government," to reflect that not all local governments may choose to identify an LGD.

Rule 903.a.(2)

In Rule 903.a.(2), when unplanned flaring occurs, the Commission clarified that notice must be provided as soon as possible after the unplanned event, but no later than 12 hours after the unplanned event. The purpose of Rule 903.a is to ensure that local emergency response agencies have the information they need to respond to calls from the public related to flaring events. Allowing unlimited time for operators to provide notice of unplanned events, rather than requiring notice as soon as possible, would obviate many of the safety and public information benefits that Rule 903.a is intended to provide, because local emergency response agencies might still have to incur expenses to unnecessarily respond to emergency calls about safe and controlled flaring events.

Consistent with prior Rule 317.p, the Commission continued to require notice to be provided to local emergency response agencies and local governments, rather than to residents. The Commission determined that these are the appropriate agencies to receive notice because they may be called upon to respond to questions and concerns about flaring events, whereas general notice to the public may provoke unnecessary concern about these controlled events.

In Rules 903.a.(1) and (2), the Commission added proximate local governments to the list of entities that should receive notice. Because flaring may be visible from within 2,000 feet, it is important for proximate local governments to be notified when flaring occurs so that they can be appropriately respond to any public concerns.

Some stakeholders suggested adding the anticipated decibel level of flaring to the notice provided pursuant to Rule 903.a.(1). Although the Commission acknowledges that flaring may cause noise impacts, the Commission did not believe that this requirement is necessary because flaring is subject to the Commission's broader noise standards under Rule 423. Should noise related to flaring pose issues, local governments may adopt additional noise restrictions or notice requirements to address the welfare of their own residents.

Rule 903.a.(3)

The Commission also added a new Rule 903.a.(3), allowing proximate and relevant local governments and local emergency response authorities to waive notice pursuant to Rules 903.a.(1) and (2). This is consistent with the Commission's overall effort to provide local governments with the ability to opt in and out of all notifications pursuant to Rule 302.f.(1).A.

Rule 903.a.(4)

The Commission added a new recordkeeping requirement in Rule 903.a.(4), requiring operators to keep records of notice provided pursuant to Rules 903.a.(1) and (2) and to provide such records to the Director upon request. Pursuant to Rule 206.f, operators must maintain such records for at least five years. Adding a recordkeeping requirement will facilitate enforcement of Rules 903.a.(1) and (2). Additionally, records of whether and when notice of flaring was provided to local governments pursuant to Rule 903.a.(2) may serve as evidence about whether a flaring event in fact meets the definition of an "upset condition" pursuant to Rule 903.c.(3).C and 903.d.(1).A.

Rule 903.b

The Commission combined portions of prior Rules 317.p, 606A, 606B, and 912.a, b, and d, into a single Rule 903.b, governing emissions during drilling operations. Prior Rule 317.p required that "[a]ny gas escaping from the well during drilling operations will be, so far as practicable, conducted to a safe distance from the well site and burned." Prior Rule 912.a prohibited unnecessary or excessive venting or flaring of natural gas produced from a well. Prior Rule 912.b required notice to the Director on a Form 4, Sundry Notice providing information about volume and content of natural gas to be flared except in limited exceptions. Prior Rule 912.d required flares to be operated as efficiently as possible to reduce air contaminants and protect public safety. Finally, prior Rules 606A and 606B each specified safe distances away from certain types of equipment where combustion could occur. The Commission streamlined and consolidated these disparate requirements into distinct Rules, 903.b, 903.c, and 903.d, which each address specific standards for venting and flaring during drilling, completion, and production operations, respectively. The Commission determined that organizing its venting and flaring rules to address specific stages of oil and gas development would provide better clarity to operators, local governments, and the public than prior Rule 912 addressing venting and flaring from all oil and gas operations in a single rule, and other 300 and 600 Series Rules addressing safe operating conditions for flares.

Rule 903.b.(1)

In Rule 903.b.(1), consistent with prior Rules 317.p and Rule 912.a, the Commission required operators to either capture or combust all natural gas that is downstream of the mud-gas separator during drilling operations, using best drilling practices while maintaining safe operating conditions. Some stakeholders suggested that the Commission identify specific technologies, such as using mud-gas separators. The Commission did not adopt these stakeholders' suggestions, because it did not want to limit operators to using any specific technology, recognizing that technology changes over time, and that improved technologies to capture drilling emissions may be developed in the future.

Rule 903.b.(2)

In Rule 903.b.(2), the Commission specified the procedure for operators to notify the Director about the need to vent natural gas during drilling operations if necessary to protect the safety of onsite personnel. The Commission recognized that there are unique safety risks associated with capturing natural gas during drilling operations, and that it may not be possible for operators to request prior approval for venting in the event of an imminent safety risk. Accordingly, the Commission required operators to provide verbal notification within 12 hours of the venting event. Additionally, the Commission provided a mechanism for operators to submit a subsequent Form 4, and where necessary, a Form 23, Well Control Report after the venting occurred, rather than seeking a formal variance from Rule 903.b.(1)'s capture or combustion requirement pursuant to Rule 502.

To formalize the Commission's intent that unplanned venting during drilling operations be limited to true emergencies to protect the safety of onsite personnel, the Commission also specified that venting pursuant to Rule 903.b.(2) may not exceed 24 hours without the operator receiving renewed approval from the Director.

Some stakeholders requested that operators submit a natural gas analysis with their Form 4. Although the Commission recognizes that this is required for natural gas that is vented at later stages pursuant to Rules 903.c.(3).B and 903.d.(3), the Commission does not believe that it is possible for operators to provide a natural gas analysis for natural gas vented at the drilling stage, because the emergency nature of such venting would likely make it impossible to capture a sufficient quantity of natural gas to analyze the sample

Rule 903.b.(3)

In Rule 903.b.(3), consistent with prior Rules 317.p, 606A, 606B, and 912.d, the Commission required that all combustors used during drilling operations be located at least 100 feet from the nearest surface hole location and enclosed. Providing a single standard specifying an objective safe distance for combustors to be located during drilling operations will provide better clarity to operators about where combustors may be safely located.

Some stakeholders suggested removing the requirement that combustors be enclosed. The Commission did not adopt these stakeholders' suggestion, because it determined that enclosing combustors is an important safety standard to minimize the risk of accidental fires, which can be spread from unenclosed combustion devices during windy periods. Enclosing combustors may also in many cases limit the visibility of flame, which may reduce calls to local emergency response agencies.

The Commission did not specify an efficiency standard for combustion devices used during drilling operations, understanding that the unique characteristics of natural gas escaping from a well during drilling operations may increase the likelihood of incomplete combustion. However, the Commission intends for operators to capture as much natural gas as possible in the event of incomplete combustion, and determined that requiring combustion devices to be enclosed facilitates this intent.

Rule 903.c

The Commission combined prior Rules 604.c.(2).C and 805.c into a single Rule 903.c.

Rule 903.c.(1)

Prior Rule 805.c provided detailed technical standards for green completion practices, which the Commission adopted in 2008 primarily as an effort to reduce odors during completion operations. Prior Rule 604.c.(2).C provided specific requirements for completion operations in designated setback locations. The Commission has successfully implemented Rules 805.c and 604.c.(2).C to reduce odors, emissions, and waste during completion operations for several years. However, after Rule 805.c was adopted, in 2012 the EPA adopted, and in 2016 revised, federal standards for reduced emission completions, which are similar to the Commission's Rule 805.c, but distinct in several ways. Since 2016, all new and modified oil and gas facilities constructed or modified have been required to comply with EPA's reduced emission completion standards, which are colloquially referred to as "OOOOa" or "Quad-O A," based on their location in subpart OOOOa of Part 60 of the Code of Federal Regulations. *See* 40 C.F.R. § 60.5375a (2019). Consistent with its obligations as an agency with delegated authority under the federal Clean Air Act, the AQCC has incorporated EPA's 2012 reduced emission completion standards by reference. *See* 5 C.C.R. § 1001-8:A.

Accordingly, to eliminate confusion that might arise from differences between the Commission's green completion standards from prior Rule 805.c and EPA's and the AQCC's reduced emission completion standards, the Commission chose to largely align its completion emissions standards with EPA and the AQCC in Rule 903.c.(1).

In July 2020, EPA revised its OOOOa new source performance standards, including 40 C.F.R. § 60.5375a. Among other changes, EPA expanded exceptions for low-pressure wells. Additionally, EPA's reduced emission completion standards (both the 2016 and 2020 versions) apply only to hydraulically fractured wells. Accordingly, the Commission did not fully incorporate EPA's 2020 reduced emission completion standards for three reasons. First, the Commission intends for its reduced emission completion standards to apply to all wells, regardless of whether they are hydraulically fractured. Second, the Commission determined that the exceptions for low-pressure wells are unnecessary given the unique circumstances of well completions in Colorado, and that they were not fully consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), and ongoing statutory obligation to prevent waste. Finally, at the time of the Commission's 800/900/1200 Mission Change Rulemaking hearing, the status of EPA's 2020 revisions to its OOOOa new source performance standards was uncertain, because the revisions were subject to active litigation. Therefore, the Commission incorporated the 2016 version of 40 C.F.R. § 60.5375a by reference in Rule 901.b.(3).G, and in Rule 903.c.(1) clarified that the reduced emission completion standards apply to all wells, regardless of whether the well is hydraulically fractured.

Although this means there will continue to be direct overlap between the Commission's Rules and the AQCC's regulations, the Commission determined that this overlap is appropriate in consultation with APCD Staff, because the Commission has historically been the primary enforcement agency for completion-stage emissions standards. The Commission will continue to closely coordinate closely with APCD staff about facilitating compliance, enforcement priorities, and avoiding duplication. Overall, the Commission determined that better aligning its completion standards with EPA and the AQCC will provide improved clarity and efficiency for operators while still fulfilling the Commission's statutory obligations to protect and minimize adverse impacts to public health and the environment and prevent waste. The Commission determined that protecting public health is particularly paramount during completion operations, because evidence in the administrative record demonstrates that health risks associated with oil and gas operations are likely greatest during completion operations such as flowback.

Some stakeholders questioned why Rule 903.c.(1) did not explicitly prohibit venting during completion operations. The Commission determined that expressly prohibiting venting during the completion stage is unnecessary, but did not intend to permit venting during the completion stage. First, based on the definition of "Commencement of Production Operations," wells would produce very little or no natural gas to vent prior to the commencement of production operations. Thus the prohibition on venting in Rule 903.d.(1) obviates the need for a distinct prohibition on venting in Rule 903.c. Second, Rule 903.c.(1)'s reduced emission completion standards require capture or combustion of natural gas in nearly all circumstances. *See* 40 C.F.R. § 60.5375a(a)(4) (2016). That leaves only flaring, rather than venting, as an alternative with the Director's prior approval pursuant to Rule 903.c.(3).

Other stakeholders raised questions about the meaning of the term "re-completed" in Rule 903.c.(1).A. The Commission intends for the term "re-completion" to refer to a completion that is not an initial completion that targets a formation that was not initially permitted for a well. Re-completions require operators to submit a Form 2, Application for Permit to Drill to obtain the Commission's approval. By contrast, re-stimulating an already completed formation does not require operators to submit a Form 2. Re-completing a well may require an operator to submit a gas capture plan pursuant to Rule 903.e even if the operator did not initially submit a gas capture plan as an attachment to their Form 2A, Oil and Gas Location Assessment. The Commission's Staff have issued guidance about form submittals related to various recompletion situations, which is available on the Commission's website, under the instructions for the Form 2.

Rule 903.c.(2)

In Rule 903.c.(2), the Commission adopted a new requirement for operators to enclose all flowback vessels and to adhere to AQCC regulations governing reducing emissions from flowback vessels. The AQCC adopted its regulations for flowback vessel emissions in 2020. The Commission accordingly determined it was appropriate to include a standard to remind operators of their obligation to enclose flowback vessels in its own Rules, to streamline compliance with both agencies' obligations. Moreover, the Commission determined that enclosure of flowback vessels will reduce emissions that may adversely impact public health and the environment, and is therefore consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). As with the reduced emission completion standards in Rule 903.c.(1), the Commission's Staff will continue to closely coordinate with APCD staff about facilitating compliance, prioritizing enforcement efforts, and avoiding duplication.

Rule 903.c.(3)

In Rule 903.c.(3), the Commission provided standards for operators to obtain the Director's approval to flare natural gas during completion operations. Operators may either obtain the Director's prior approval when submitting a gas capture plan as an attachment to their Form 2A pursuant to Rule 903.e, or by subsequently submitting a Form 4. The Form 4 must include similar information to a gas capture plan, including why the flaring is necessary to complete the well, estimating a volume and duration of flaring, and explaining why the operator is unable to connect its facility to a gathering line. This is consistent with the Commission's March 18, 2016 NTO re: Rule 912.

In Rule 903.c.(3).C, the Commission adopted standards for combusting natural gas in order to protect safety of onsite personnel and during upset conditions. Among the reasons that flaring may be permissible to protect safety pursuant to Rule 903.c.(3).C are to purge oxygen from the line. For this type of unplanned flaring event during completion, operators may obtain the Director's subsequent approval by submitting a Form 4 within 7 days. However, the Commission limited the upset conditions and safety emergencies that will authorize flaring without prior Director approval pursuant to Rule 903.c.(3).C to periods not to exceed 24 cumulative hours. If flaring pursuant to an upset condition exceeds 24 hours, then operators must obtain the Director's approval to continue flaring. The Commission determined that this appropriately balanced the need for operators to react quickly to upset conditions and safety emergencies with ensuring that unnecessary and excessive venting and flaring does not occur.

Some stakeholders raised questions about the use of the term "emission control device" in Rule 903.c.(3).C. Because sending separable gas from a well or a separator to an emissions control device would meet the 100 Series definition of "Flaring," the Commission adopted standards to regulate such activities in Rule 903.c.(3).C.

Rule 903.d

The Commission combined portions of prior Rules 805.b, 912.a, 912.b, 912.c, and 912.d into a single Rule 903.d, providing a clearer standard for venting and flaring during production operations.

Consistent with these changes, the Commission eliminated prior Rules 805.b.(2).A, B, and D, which addressed emissions from tanks, glycol dehydrators, and pneumatic devices, respectively. Because AQCC regulations set emissions standards for these types of equipment, the Commission determined that it was unnecessarily duplicative to continue setting its own distinct standards for those categories of equipment.

Rule 903.d.(1)

Consistent with prior Rule 912.a, in Rule 903.d.(1), the Commission prohibited venting and flaring of natural gas produced from a completed well after the commencement of production operations, except under certain enumerated exceptions.

Some stakeholders questioned whether the reference to "natural gas produced from any Completed Well" in Rule 903.d.(1) includes natural gas vented or flared at the production site, but not at the well itself. The Commission does intend to prohibit venting and flaring at the entire oil and gas location during production operations, rather than restricting Rule 903.d to only wellhead (also known as casinghead) gas. The Commission accordingly used the term "gas produced from any Completed Well" to include all natural gas produced from a well at an oil and gas location, up to the point of the sales meter.

The first enumerated exception in Rule 903.d.(1).A is for natural gas flared or vented during an upset condition. As discussed above, the Commission also adopted a new definition of "Upset Condition" in its 100 Series Rules. The Commission intends for Rule 903.d.(1).A to cover each individual upset at a facility, not to be cumulative of all upsets that ever occur at a facility. Rule 903.d.(1).A makes venting and flaring permissible for a period of time necessary to address and resolve the upset condition, but for a period not to exceed 24 cumulative hours per upset condition. The 24 cumulative hours may be non-consecutive. Thus, *each* upset condition permitted by Rule 903.d.(1).A may involve only 24 total hours of flaring or venting. The Commission also adopted recordkeeping requirements in Rule 903.d.(1).A. Any documentation of the upset condition requested by the Director will be included in the well file for transparency.

The second enumerated exception in Rule 903.d.(1).B is for natural gas vented during, and as part of, active and required maintenance and repair activity, including pipeline pigging. So long as operators utilize best management practices to minimize the venting during maintenance activities, the Commission does not intend to prohibit this venting. To be subject to this exception, the venting must be part of "active and required" maintenance. The reference to "active" maintenance is intended to clarify that while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited.

Earlier drafts of Rule 903.d.(1) provided for exceptions intended to address circumstances where the AQCC's regulations explicitly authorize venting or flaring during production operations. The Commission's Staff initially proposed these exceptions to alleviate confusion about the categories of emissions covered by the definitions of venting and flaring. But the final versions of the definitions of "Venting" and "Flaring," described above, obviate the need for these exceptions. Accordingly, the Commission did not adopt these exceptions. However, the Commission retained the exception for active and required maintenance, because some venting will occur during maintenance activities.

Some stakeholders questioned whether the maintenance referenced in Rule 903.d.(1).B includes applying out of service locks and tags ("OOSLAT") to flowlines. The Commission does intend for Rule 903.d.(1).B to include applying OOSLAT to flowlines.

The third enumerated exception in Rule 903.d.(1).C is for natural gas flared during a production evaluation or productivity test that is approved by the Director on a gas capture plan pursuant to Rule 903.e. This is consistent with prior Rule 912.b. The Commission recognizes that the unique circumstances associated with wildcat or exploratory wells may make flaring necessary for a limited period of time after the commencement of production operations while the operator is conducting tests to determine whether the well is capable of producing oil or gas in economic quantities. However, to ensure that flaring does not continue indefinitely if the wildcat well does prove to be economic, the Commission limited the permissible duration of the Rule 903.d.(1).C exception to 60 days. This is consistent with the Commission's current practice and standards in other jurisdictions. However, the Commission intentionally used the term "not to exceed" 60 days in Rule 903.d.(1).C because it recognizes that there will be many circumstances where a shorter duration for flaring is appropriate. The Commission and Director will have an opportunity to review gas capture plans prior to wildcat or exploratory wells being drilled, and where appropriate may limit the permissible duration of flaring to 30 days where such a limited duration is feasible due to the proximity to gathering infrastructure. Unlike prior Rule 912.b, in Rule 903.d.(1).C, the Commission did not include venting as a permissible activity at wildcat or exploratory wells during productivity tests or production evaluations. The Commission determined that in almost all circumstances, flaring will be possible and venting will not be necessary at such wells. However, in the limited circumstances where venting may be necessary during a production evaluation, operators may request a variance pursuant to Rule 502 in the course of seeking approval of their gas capture plans pursuant to Rule 903.e.

The fourth enumerated exception in Rule 903.d.(1).D is for natural gas vented during a Bradenhead test pursuant to Rule 419. The Commission recognizes that venting is necessary during such tests, which is an important component of ensuring wellbore integrity, and determined that the negligible public health, safety, and environmental impacts of such venting are outweighed by the public health, safety, and environmental benefits of ensuring wellbore integrity. The Commission will address the permissible duration of venting during Bradenhead tests in guidance documents that its Staff will develop for implementing the Commission's recently-adopted Wellbore Integrity Rules. However, the Commission anticipates that venting associated with Bradenhead tests will be limited to 30 minutes except in very rare circumstances. In some circumstances, additional information necessary for the Bradenhead test may be obtained by extending the duration of the test beyond 30 minutes.

The fifth enumerated exception in Rule 903.d.(1).E is for natural gas vented or flared during well liquids unloading that employs best management practices required by AQCC Regulation Number 7, Part D, Section II.G, 5 C.C.R. § 1001-9:D.II.G. The Commission used the term "well liquids unloading" to refer to maintenance operations or other operations where there is intentional release of natural gas from the wellbore to the atmosphere in order to facilitate the unloading of liquids from the wellbore. This is sometimes referred to as "manual" unloading. This is the same context in which the AQCC regulations use the same term. The Commission does not intend for the term "well liquids unloading" to refer to the normal production cycle of a well, which may include intermittent cycling or unloading of wellbore fluids, such as through the use of a plunger lift pump. The Commission's intent is to reduce venting associated with all manual practices intended for well maintenance. These manual practices include swabbing. The Commission recognizes that this may require some operators to increase flaring volume capacity.

Because the AQCC regulations do not specify the best management practices for well liquids unloading, the Commission clarified that operators must capture or flare natural gas vented during well liquids unloading if the escape of the natural gas poses safety risks, such as in close proximity to residential development. The Commission intends for its Staff to work with operators to identify best management practices for well liquids unloading on a case-by-case basis.

To facilitate its Staff working with operators to identify best management practices for well liquids unloading, the Commission adopted a new requirement for operators to submit a Form 42, Field Operations Notice – Notice of Well Liquids Unloading, at least 48 hours prior to conducting the well liquids unloading operation, unless providing notice 48 hours in advance would require the operator to conduct an alternative method of unloading (such as swabbing or other methods that might require a rig), or otherwise extending the unloading period in a manner that increases emissions. In such a circumstance, the operator must provide notice as soon as possible. For Form 42s filed pursuant to Rule 903.d.(1).E.ii, the Commission's intent is for notice to be provided as soon as the operator is able to provide notice. The use of the term "as soon as possible" is not intended to indicate that notice should be given immediately prior to unloading in most circumstances. The Commission intends that an operator providing less than two hours notice would only occur in rare and exceptional circumstances.

All well liquids unloading events, including swabbing, must be reported. Like other

Form 42 notices, receipt of the Form 42 will allow the Commission's Staff to determine whether it is appropriate to deploy Field Inspection staff to observe the well liquids unloading event. It will also provide the Commission's Staff with better information about how frequently well liquids unloading events occur. The Commission intends for the Form 42 notice of well liquids unloading to be sent to the relevant local government, consistent with Rule 405.s. The Commission also intends for the notice of well liquids unloading to be shared with the APCD, at that agency's request.

The purpose of requiring a Form 42 notice of well liquids unloading is to ensure that the Commission's Staff, the APCD, and local governments receive real-time notice of well liquids unloading events, which may be associated with high emissions. This allows for more timely observation and response than the relatively infrequent reporting required by AQCC regulations. This more frequent reporting will allow the Commission's Staff to consider trends in certain areas of a basin, better inform best management practices, allow Field Inspection staff to conduct inspections, and allow the Commission's Staff and the APCD to link potential spikes in monitored emissions to specific activities.

The sixth enumerated exception in Rule 903.d.(1).F is for flaring and venting at facilities that existed prior to the effective date of the 800/900/1200 Mission Change Rulemaking, that was either already approved on a Form 4 under prior Rule 912, or is subsequently approved by the Director under Rule 903.d.(3). The Commission intends for the standards in Rule 903.d.(1) to apply to both new and existing facilities, but recognizes that some existing oil and gas wells and locations are not connected to gathering line infrastructure. As discussed in Rule 903.d.(3), below, the Commission intends for these existing facilities to connect to gathering lines to capture, rather than flare, produced natural gas, or otherwise put gas to beneficial use, but recognizes that it will take some time for all such facilities to do so.

Rule 903.d.(2)

To provide sufficient regulatory oversight of venting and flaring permitted through the enumerated exceptions in Rule 903.d.(1), in Rule 903.d.(2), the Commission adopted reporting requirements for permitted venting and flaring that exceeds eight consecutive or 24 cumulative hours. This will allow the Commission to ensure that none of the enumerated exceptions in Rule 903.d.(1) are abused or extend for a longer period than intended. The Commission anticipates that this will only apply to a limited number of the exceptions in Rule 903.d.(1), including venting and flaring pursuant to Rules 903.d.(1).A, B, and C, but adopted the requirement for all of the venting and flaring exceptions except for Rule 903.d.(1).F in order to provide oversight for any unexpectedly long duration venting and flaring events.

Consistent with Rules 903.c.(3).B and 903.d.(3), the Commission required operators to report information about the venting and flaring events on a Form 4, including the volume and content of the natural gas vented or flared, a gas analysis, and an explanation of the event. If there is not yet natural gas from a new well to obtain a sample, the operator may provide an analogue from an offset well with the Director's approval. Once gas is available from the well for which the operator submitted the Form 4, the operator will submit a sample of the gas from that well within 30 days.

For any Form 4 submitted pursuant to Rule 903.d.(2) for maintenance and repair activities that exceed 8 consecutive or 24 cumulative hours, the Commission intends for operators to specify what operational best practices will be used to minimize venting.

Although local governments should receive notice of all flaring incidents pursuant to Rule 903.a, if a local government needs additional information about the flaring event, it may request access to the Form 4 from the Commission's Staff on a case-by-case basis.

For venting or flaring subject to the Rule 903.d.(1).E exception for liquids unloading, the Commission intends for Rule 903.d.(2) to apply on a location-wide basis, meaning that the 8 consecutive hours or 24 cumulative hours applies to all unloading activities at a location, not to unloading activities at individual wells.

<u>Rule 903.d.(3)</u>

Consistent with prior Rule 912.b, in Rule 903.d.(3), the Commission adopted reporting and approval requirements for ongoing venting and flaring at existing wells that were routinely venting or flaring natural gas prior to the effective date of the 800/900/1200 Mission Change Rulemaking, either because they were not connected to a gathering line, were connected to a gathering line with insufficient takeaway capacity, or were not otherwise putting natural gas to beneficial use in lieu of directing it to a sales line. Rule 903.d.(3) only applies to this subset of existing wells that were routinely venting or flaring for one of the reasons specified in the Rule, and if an operator of such a well must vent or flare for one of the reasons in Rule 903.d.(1), independent of its lack of gathering capacity, nothing in Rule 903.d.(3) prohibits the operator from doing so.

As was previously required by prior Rule 912.b and the Commission's March 18, 2016 NTO re: Rule 912, operators must submit Form 4s to the Commission to obtain approval to vent or flare natural gas on an ongoing basis from producing wells. Under that NTO, all approvals to vent or flare expired within 1 year of the approval date. The Director must approve the operator's request to vent or flare for the operator to be permitted to vent or flare—mere submission of the Form 4 does not confer permission. Rule 903.d.(3) grants the Director the authority to deny approval of requests to flare or vent if necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources, or to prevent waste.

The Commission recognizes there are areas of the state, such as Jackson County, where infrastructure limitations have resulted in high volumes of flaring for a lengthy period of time. Consistent with its statutory obligation to prevent waste, the Commission intends to phase out routine venting and flaring from producing wells within one year of the effective date of the 800/900/1200 Mission Change Rulemaking. The Commission recognizes that some time is necessary for infrastructure issues to be resolved.

Accordingly, in Rule 903.d.(3), the Commission authorized the Director to approve at most a one-time, twelve month request to continue venting and flaring, which will allow sufficient time for operators to make progress towards connecting to gathering infrastructure. Specifically, operators of existing wells that were routinely venting and flaring prior to January 15, 2021 must file a Form 4, requesting permission to continue venting and flaring, by no later than the date their prior Form 4 expires, and in no case later than January 15, 2022. This will ensure that all wells that were routinely venting and flaring prior to the effective date of the 800/900/1200 Mission Change Rulemaking will request permission to continue to vent or flare within 1 year of the effective date. The Commission's Staff may approve a request to continue venting or flaring for a maximum period of 12 months, but in no case will the Commission's Staff approve a request to continue venting and flaring beyond January 15, 2022. Thus, if an operator's prior Form 4 approval to vent or flare under prior Rule 912 expires in December 2021, and the operator submits a request to continue venting and flaring in December 2021, the Commission's Staff could only approve the request for a duration of one month, through January 15, 2022, rather than approving it for a full 12-month period.

Though disfavored, Operators may request an extension to the one-time request to flare or vent natural gas by seeking a variance from the Commission pursuant to Rule 502. After the end of the 12 month period, wells that have been subject to a 12 month flaring or venting exception may flare or vent for any of the reasons set forth in Rules 903.d.(1).A—E without submitting a variance request pursuant to Rule 502.

To clarify the intent of this category of Form 4, the Commission will create a new tab on the Form 4 that will be labeled a gas capture plan for this subset of requests for permission to vent or flare. The Commission codified and slightly modified the specific reporting criteria on the Form 4, Gas Capture Plan based on the March 18, 2016 NTO in Rules 903.d.(3).A–E. As an added incentive for operators to connect existing wells to gathering infrastructure or otherwise put natural gas towards beneficial use, the Commission required operators to explain on the Form 4, Gas Capture Plan, whether the mineral owner was compensated for the vented or flared natural gas. Although the Commission does not intend for its Staff to be involved in private contract disputes, this will provide an added incentive for operators to connect to gathering infrastructure or otherwise put natural gas towards beneficial use by making it clearer to mineral owners whether they are being compensated for the value of natural gas wasted through routine venting and flaring.

The Commission recognizes that situations may arise in which an operator unexpectedly loses access to a gathering line due to unforeseen circumstances outside of the operator's control, even if those existing wells were not flaring on January 15, 2021. The Commission acknowledges that such a circumstance could arise after January 15, 2022, and does not intend to preclude an operator from requesting approval to vent or flare in such a situation. Should such a situation arise after January 15, 2022, the Operator could submit a Form 4 pursuant to Rule 903.d.(3), and request permission to vent or flare natural gas for up to 12 months. The Commission prefers that operators flare, rather than vent, under such a circumstance. The Commission intends operators to promptly notify the Director if they lose access to a gathering line, and accordingly specified that such Form 4s must be submitted within 30 days of the operator losing gathering line access. The operator may not vent or flare until the Commission's Staff approves the Form 4. The Commission's Staff may approve such Form 4s for a period of no longer than 12 months.

Rule 903.d.(4)

The Commission moved prior Rule 912.c, governing measurement and reporting of natural gas vented, flared, and used at oil and gas locations to Rule 903.d.(4).A. The Commission made several non-substantive revisions to the Rule to improve clarity.

Some stakeholders raised concerns about whether both routine and non-routine venting and flaring must be reported. Consistent with ongoing practice, the Commission intends for all natural gas vented or flared to be reported on a Form 7, Operator's Monthly Report of Operations but added the word "all" to Rule 903.d.(4).A to resolve any ambiguity. To address questions that have arisen under prior Rule 329 about whether vented or flared natural gas is "removed from the lease," Rule 903.d.(4).A makes clear that if natural gas has been removed from a formation, it must be reported on a Form 7.

Some stakeholders also raised concerns that Rule 903.d.(4) unnecessarily duplicated AQCC emissions inventory reporting requirements. Based on consultation with APCD staff, the Commission does not agree with these stakeholders. The AQCC's emissions inventory rules require subsequent reports of emissions after they occur, and only require advance emissions estimates for well liquids unloading. Accordingly, the only duplication between the two sets of requirements is the advance estimate of well liquids unloading emissions, and the Commission determined that this minor degree of duplication is reasonable.

The Commission adopted a new Rule 903.d.(4).B requiring operators to expand reporting requirements about the volume of natural gas vented, flared, or used on-lease to include mineral owners, rather than solely being reported to the Commission on a Form 7 pursuant to prior Rule 912.c. The Commission adopted this Rule to provide an additional incentive for operators to avoid waste and capture natural gas or put it to a beneficial use. The Commission does not intend for its Staff to become involved in lease or contract disputes between operators and mineral owners. However, the Commission intends for the reporting under Rule 903.d.(4).B to provide mineral owners with additional information about the potential waste of natural gas that they own, which may incentivize operators to capture more natural gas. To ensure that Rule 903.d.(4).B is enforceable, the Commission required operators to maintain records of notice provided and provide the records to the Director upon request. Some stakeholders raised questions about the duration of the recordkeeping requirement in Rule 903.d.(4).B. The Commission intends for operators to maintain such records for at least five years, pursuant to Rule 206.f.

Rule 903.d.(5)

The Commission moved prior Rule 912.d, which set standards for combustion devices, to Rule 903.d.(5). The Commission revised Rule 903.d.(5) to better align with AQCC regulations governing destruction efficiency for emissions control devices. *See, e.g.*, 5 C.C.R. § 1001-9:D.II.C.1.b. The Commission also specified that such devices must be equipped with an auto-igniter or a continuous pilot light as an important safety precaution. As discussed above, the Commission also required combustion devices to be enclosed to protect public safety, including by preventing unintentional wildfires set by malfunctioning unenclosed flares. Several stakeholders raised questions about individual circumstances where complying with Rule 903.d.(5) may prove challenging. As with all of the Commission's Rules, operators may seek variances from Rule 903.d.(5) pursuant to Rule 502 where necessary.

The Commission intends for operators to maintain flare or combustor specifications showing that the flares or combustors used for flaring pursuant to Rule 903.d.(5) are designed to handle the gas flowrate potential and heat content expected in the streams to be combusted to achieve 98% design destruction efficiency. Operators may supply this information on a gas capture plan submitted pursuant to Rule 903.e.

Rule 903.d.(6)

The Commission moved prior Rule 805.b.(2).C to Rule 903.d.(6). Consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, *see* C.R.S. § 34-60-106(2.5)(a), the Commission made several substantive changes to the Rule to protect public health, public welfare, and the environment from emissions from pits located in close proximity to residences, in ozone nonattainment areas, and statewide.

Rule 903.d.(6).A

The Commission adopted a new Rule 903.d.(6).A, governing emissions from new pits, which refers to pits constructed after January 15, 2021.

Pursuant to Rule 903.d.(6).A.iv, all new pits, regardless of whether they are located, must be designed and operated to use control technologies to minimize emissions. The Commission determined that minimizing emissions is important to reduce public health impacts from pits, regardless of where they are constructed. Rule 903.d.(6).A.iv uses the term "reasonably achievable based on best available practices." This term is intended to encourage operators to use innovative technologies to reduce emissions. It is not intended to reference the Clean Air Act's "reasonable available control technology" ("RACT") standard.

The Commission adopted a tiered structure for permissible emissions from new pits, based on the specific categories of risks posed to public health.

Because emissions of hazardous air pollutants may pose health risks based on proximity, in Rule 903.d.(6).A.i, the Commission set a two tons per year ("tpy") volatile organic compound ("VOC") emission limit for pits within 2,000 feet of a building unit or designated outside activity area. This is consistent with Rules 304.b.(2), 604.b, and 907.b.(5).G that protect public health by setting a default rule that emissions sources that may adversely impact public health should be located at least 2,000 feet from residential building units. This proximity-based emissions limit will also protect public welfare by reducing the odor impacts of pits, consistent with prior Rule 805.b.(2).C. The Commission determined that continuing to allow five tons per year of VOC emissions is too great a health risk in such close proximity to areas where people live and recreate. Based on evidence in the administrative record about the potential health risks posed by proximity to oil and gas facilities with VOC emissions, the Commission determined that it is necessary and reasonable to adopt emission standards that are more protective for pits that are in closer proximity to building units than for those that are farther away from building units. This is consistent with the rationale underlying the Commission's prior Rule 805.b.(2).C, which applied an emissions standard to reduce odors from pits that were in closer proximity to building units, but did not limit the emissions of pits located farther away from building units. Finally, the Commission determined that adopting a more protective emissions standard for pits is consistent with its statutory obligation to prevent waste, because it will incentivize operators to reduce waste by appropriately tuning separators to reduce the flow of hydrocarbons into pits.

Emissions of VOCs from pits may also contribute to tropospheric ozone formation, which harms public health. Rule 903.d.(6).A.ii therefore sets a two tpy VOC emission limit for pits within the nine-county Denver-Metro/Northern Front Range ozone nonattainment area. The Commission acknowledges that emissions of VOCs from outside the nonattainment area may also contribute to ozone formation, but determined that focusing on reducing ozone precursor emissions within the nonattainment area is most directly tied to protecting public health from unhealthy ambient atmospheric concentrations of ozone.

Although the public health risks are less acute when pits are located farther away from sensitive receptors, emissions of VOCs from pits nevertheless contribute to tropospheric ozone formation, and emissions of methane from pits nevertheless contribute to climate change, throughout the state of Colorado. Accordingly, in Rule 903.d.(6).A.iii, the Commission set a statewide emissions limit of 5 tpy for new pits that are not located within 2,000 feet of a building unit or within the nine-county ozone nonattainment area.

The Commission recognizes that some pits are used for recycling and reuse of produced water. Throughout the 200–600 and 800/900/1200 Mission Change Rulemakings, the Commission sought to incentivize reuse and recycling of produced water, recognizing the importance of reducing water quantity impacts in Colorado due to scarce water supplies, and climate change making future droughts more likely. Accordingly, the Commission provided an exception from Rule 903.d.(6).A.iii for pits used for produced water reuse and recycling. New pits need not comply with the 5 tpy VOC emissions limit that would otherwise apply if they meet all three of the following criteria: 1) they are used for reuse and recycling and submit a reuse and recycling plan as an attachment to their Form 15, Earthen Pit Permit/Report application; 2) they use a centralized pipeline distribution system to minimize truck traffic; and 3) they take other steps approved by the Director to minimize emissions, even if emissions are not minimized to 5 tpy. The Commission determined that these are reasonable and necessary criteria to appropriately incentivize reuse and recycling of produced water, while protecting public health by achieving emissions benefits from reducing truck traffic and minimizing emissions from produced water recycling pits to the maximum extent possible.

Rule 903.d.(6).B

The Commission maintained the 5 tpy VOC emissions limit for existing pits from prior Rule 805.b.(2).C, and expanded it statewide. The Commission intends for this regulatory change to apply retroactively to all existing pits statewide because of Senate Bill 19-181's changes to the Commission's mission and statutory authority to protect public health. C.R.S. § 34-60-106(2.5)(a). The Commission determined that stronger protections are necessary for public health from these existing pits, to reduce potential health impacts for nearby residents, reduce ozone precursor emissions, and combat climate change.

The Commission recognizes that not all operators will have a readily available estimate of emissions from current pits. And pits that are not within 1,320 feet of a building unit would not have been required to comply with prior Rule 805.b.(2).C's 5 tpy emissions limit. Accordingly, to give operators of existing pits time to determine the applicability of the Rule and to come into compliance, the Commission created a two-year grace period. This will allow operators to conduct produced water quality analysis pursuant to Rule 909.j, and use that data and emissions estimation guidance developed by the Commission's Staff to calculate pit emissions. The Commission allowed for a 6-month period between submission of the determination of applicability under Rule 903.d.(6) on July 15, 2022 and the date of compliance, January 15, 2023, to give operators time to work with Staff on plans for coming into compliance with the 5 tpy emissions standard, or to request one of the available exceptions.

The Commission created two exceptions to Rule 903.d.(6).B. First, as discussed above, the Commission intends to incentivize the reuse and recycling of produced water, while also reducing emissions from both pits and truck traffic. Accordingly, operators may request an exception from Rule 903.d.(6).B for pits used for recycling or reuse of produced water, so long as the pit utilizes control technologies to reduce emissions to the extent reasonably achievable, and subject to a reuse and recycling plan submitted for Staff's review and approval pursuant to Rule 905.a.(3). Second, an operator may request an exception by submitting a Form 15 that demonstrates that a higher emissions limit is necessary and reasonable, which the Director will review in consultation with the APCD to determine whether a higher emissions limit is permissible on a case-by-case basis. The Commission determined that it is appropriate for the Director to make such a decision, after consultation with the APCD, rather than elevating the decision to a Commission-level variance pursuant to Rule 502, because of its highly technical nature and because of the potential for a large volume of exception requests.

Some stakeholders questioned whether Rule 903.d.(6).B would apply to pits where a building unit was built or a designated outside activity area was designated after the pit was already constructed. The Commission does not intend for Rules 903.d.(6).A or B to apply in such a situation, which is why the Commission used the terms "design, construct, and operate" in Rule 906.d.(6).A and "operated" in Rule 906.d.(6).B, which is a change from prior Rule 805.b.(2).C which used the term "located" rather than "constructed."

Finally, some stakeholders suggested that reducing the permissible emissions from existing pits would be inconsistent with AQCC permitting standards. Based on consultation with APCD staff, the Commission does not agree with these stakeholders. Although operators may include emissions from pits in permit applications submitted to the AQCC, or specify RACT for such pits, the AQCC does not have a substantive regulation that sets a specific emission limit for pits. Therefore the Commission changing the emissions threshold in its own Rules will not interfere with the AQCC's rules or permits.

Rule 903.d.(6).C

The Commission also adopted a new Rule 903.d.(6).C, requiring operators to submit the basis for their determination of applicability of Rule 903.d.(6) on a Form 15 for both new and existing pits. The Form 15 would be submitted concurrently with the initial produced water quality analysis required by Rule 909.j, and thus by no later than July 15, 2022 for existing pits. Operators would submit the determination of applicability as part of the Form 15 permit application for a new pit pursuant to Rule 908. The Form 15 determination of applicability will specify the operator's estimated annual emissions, the method used to calculate those emissions, and the rationale for any exception the operator requests for an existing pit pursuant to Rules 903.d.(6).B.i or ii.

The Commission's Staff currently have limited information available to ensure compliance with prior Rule 805.b.(2).C, and operators submitting applicability determinations will provide the Commission's Staff with the information necessary to better identify pit emissions levels and enforce Rule 903.d.(6). The Commission intends for its Staff to develop guidance about methods to correctly estimate pit emissions. The Commission intends for this guidance to be issued promptly, but to be updated periodically based on any metrics or calculations developed by the Pit Emissions Working Group described below.

The Commission anticipates that the analysis of dissolved and entrained VOCs in produced water source analysis will provide a reasonable indication of emission rates. Specifically, the Commission anticipates that operators may use data about hydrocarbon content (including BTEX and total petroleum hydrocarbons ("TPH")) gathered pursuant to the produced water characterization required by Rule 909.j.(1) to calculate VOC emissions from pits. The Commission reviewed efforts by regulatory agencies in Wyoming and California, which have each developed metrics to equate produced water sampling for hydrocarbons into pit emissions levels.[6] However, the Commission may consider requiring conditions of approval to monitor and model actual pit emissions on a case-by-case basis as appropriate.

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[6] *See* Cal. Air Res. Bd., *Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations: Final Report* (May 2020), https://ww2.arb.ca.gov/sites/default/files/2020-07/CARB%20Oil%20Wastewater%20Emissions%20Final%20Report_05.11.2020_ADA.pdf; Wyo. Dep't Envtl. Qual., *WYoming Pond Emission Calculator: Initial User Training* (Dec. 2019), http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/WYPEC_training_presentation_16dec2019.pdf; Wyo. Dep't Envtl. Qual., *Wyoming Pond Emissions Calculator (WYPEC)* (updated Jan. 17, 2020), http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/WYPEC_v1-1_17jan2020%20(1)%20-%20Copy.xlsm.

The aid the Commission Staff in developing guidance for pit emissions calculation, and to aid operators in complying with Rule 903.d.(6), the Commission instructs its Staff to promptly convene a stakeholder working group. The Commission intends for the working group to both develop better methods for calculating pit emissions, and to assist operators and Staff in identifying better emissions control technologies and practices for pits. The stakeholder working group should include both Commission Staff and staff from the APCD, as well as representatives from interested local governments, operators, and community organizations. The stakeholder working group should:

- Investigate methods for calculating pit emissions in each major oil and gas producing basin in Colorado and develop a pit emissions tool that allows operators to use produced water quality analysis conducted pursuant to Rule 909.j to calculate or estimate pit emissions;

- Review air monitoring data to reconcile measured emissions of VOCs with produced water quality analysis data;

- Consider data gathered through the pit information update process required by Rule 909.a;

- Consider alternatives to pits and any emissions benefits or disbenefits from alternative means of produced water storage, management, reuse, and recycling; and

- Investigate technologies that effectively reduce emissions from pits to improve understanding about reasonably available emissions reduction technologies.

The Pit Emissions Working Group may recommend regulatory changes based on its investigation. The Commission directs Staff to coordinate a report back to the Commission based on the results of the Pit Emissions working Group by no later than January 15, 2022.

Rule 903.e

The Commission adopted a new Rule 903.e, requiring operators to either certify their commitment to connect to a gathering line, or a submit a gas capture plan as an attachment to a Form 2A pursuant to Rule 304.c.(12). The Commission's prior Rule 912 set substantive standards for venting and flaring, but did not provide the Commission's Staff and operators with an opportunity to plan for natural gas capture as part of the permit application process. The Commission adopted Rule 903.e to close that regulatory gap, because the Commission determined that front-end planning for how natural gas produced at an oil and gas location will be captured for beneficial use, either on-site or by connecting to a gathering line, will obviate the need for subsequent venting and flaring in most cases. Other jurisdictions, including New Mexico, North Dakota, and Wyoming have adopted gas capture plan requirements. Based on its review of gas capture planning processes in these other jurisdictions, the Commission determined that requiring gas capture plans is an effective method to implement its statutory obligation to prevent waste and protect public health, safety, welfare, the environment, and wildlife resources. Although the Commission reviewed gas capture plans from other jurisdictions, the gas capture plan requirements it adopted in Rule 903.e are not identical to requirements in other states, because the Commission determined it was necessary to tailor its gas capture requirements to its own unique permitting process and other factors unique to Colorado.

Rule 903.e.(1)

Rule 903.e.(1).A specifies the two options for operators to demonstrate to the Commission that they will capture all of the natural gas produced at a proposed well as part of a Form 2A application. Operators may choose to either certify that they will connect to a gathering line by the commencement of production operations, or submit a gas capture plan demonstrating the operator's plans to either connect to a gathering line, or, where doing so is not feasible, use other methods to beneficially use all natural gas produced by the well, rather than venting or flaring it. A commitment to connect to a gas gathering line represents an operator's commitment to connect to a gas gathering line with adequate takeaway capacity for all of natural gas anticipated to be produced from the well.

In Rule 903.e.(1).B, the Commission provided substantive standards for the contents of gas capture plans. These criteria are intended to provide opportunities for operators to demonstrate their plans for connecting to gathering infrastructure or otherwise put natural gas to beneficial use, and to work through any issues with the Commission's Staff during the permitting process.

The Commission specified that operators may identify either the closest or contracted natural gas gathering system in Rules 903.e.(1).B.i & ii, recognizing that some operators may have exclusive gathering contracts with gathering systems that are not necessarily the closest to a planned oil and gas location. However, the Commission encourages operators to utilize existing infrastructure wherever possible. If an operator does not intend to connect to the closest existing gathering line, the Commission expects the operator to explain why it does not plan to do so in its gas capture plan. The Commission intends for its Staff to consider the proximity of planned gathering line infrastructure as part of the alternative location analysis pursuant to Rule 304.b.(2). The Commission nevertheless recognizes that operators are constrained not only by physical limitations (such as the proximity to a gathering system), but also contractual obligations (pre-existing contracts, or volume limits on existing gathering lines).

Some stakeholders raised concerns with the requirement to discuss potential rights of way issues in Rule 903.e.(1).B.iii, because they believe that information submitted in a gas capture plan could potentially be confidential. The Commission did not make substantive changes to the Rule in response to the stakeholders' concerns, because all confidentiality protections for confidential business information pursuant to Rule 223 would apply, and confidential information would not be publicly disclosed by the Commission. Specifically, Rule 223.b ensures that any confidential information submitted with a gas capture plan will remain confidential because Rule 223.b.(3) makes monetary amounts, payments, and personal information listed on a right-of-way or easement agreement confidential, and Rule 223.b.(4) makes information about ongoing negotiations for potential routes of gathering system infrastructure, including information concerning landowner negotiations, confidential. This information, if submitted with a gas capture plan, would be fully protected under the Commission's Rules and the Colorado Open Records Act, and therefore the Commission determined that confidentiality does not pose any barrier to requiring the submission of a gas capture plan.

Rule 903.e.(1).B.iii.ee provides a non-exclusive list of potential beneficial uses for natural gas that are alternatives to directing the natural gas to a gathering line, venting, or flaring. The Commission recognizes that there are other beneficial uses of natural gas that are not explicitly listed in Rule 903.e.(1).B.iii.ee, and the omission of any such use does not indicate the Commission's intent to prohibit such activities. Specifically, the Commission recognizes that gathering a portion of natural gas and using it as a fuel supply or for gas lift to assist production constitutes a beneficial use.

Rules 903.e.(1).B.v–viii are intended to provide the Commission's Staff with information about how the operator will minimize emissions from various forms of venting and flaring that are permissible pursuant to Rules 903.b and 903.d.(1). If an operator certifies connection to a gathering line rather than submitting a gas capture plan, the Commission intends for the operator to supply the information listed in Rules 903.e.(1).B.v–viii on the cumulative impacts plan required by Rule 304.c.(19), rather than on the gas capture plan. In all cases, an operator must submit the information listed in Rules 903.e.(1).B.v–viii, regardless of whether the operator submits a gas capture plan, because the information is important for the Commission's Staff irrespective of whether a well is connected to a gathering line.

The purpose of requiring information about anticipated volumes of liquids and gas production, and a description of separation equipment sizing in Rule 903.e.(1).B.viii is to provide the Commission's Staff an opportunity to work with operators to ensure that separation equipment is appropriately sized. The Commission recognizes that inappropriately sized separation equipment is a major cause of wasteful venting and flaring. The Commission accordingly tailored its definition of venting to ensure that improper equipment design that results in the waste of natural gas is defined as venting. Because appropriate separation equipment size varies over the life of a well, the Commission intends for the information in Rule 903.e.(1).B.viii to apply throughout the life of the well. At the start of production operations, when gas production is high the optimal separation equipment size is different than at the end of a well's life. The Commission intends for the information supplied pursuant to Rule 903.e.(1).B.viii to address how equipment will change over time as production decreases, to ensure that separation equipment is never below the production capacity. The Commission does not intend for operators to remove gas capture equipment based solely on economic considerations if this would result in waste of natural gas that otherwise could be captured and put to beneficial use.

Rules 903.e.(2) & (3)

In Rules 903.e.(2) and (3), the Commission adopted standards to ensure that operators comply with the certifications and gas capture plans approved by the Commission when a facility is constructed. The Commission required operators to verify that their facility has been connected to a gathering line by submitting a Form 10, Certificate of Clearance pursuant to Rule 219.

If an operator does not connect its facility to a gathering line despite certifying that it would do so on the Form 2A, or stating that it would do so on a gas capture plan approved by the Commission, then Rule 903.e.(3) authorizes the Director to require the operator to shut in a well until the well is connected to a gathering line. Rule 903.e.(3) also authorizes the Director to require the operator to shut in a well if the operator does not comply with its own gas capture plan which includes a plan for beneficial use of natural gas.

Pursuant to Rule 301.c, operators may request a modification to their gas capture plan if unforeseen circumstances make the operator unable to connect to a gathering line or otherwise comply with their gas capture plan. Rule 301.c specifies the process for the Director, and if necessary, the Commission, to approve modification to the terms of an oil and gas development plan, including gas capture plans.

The Commission also specified that operators may request a hearing before the Commission pursuant to Rule 503.g.(10) if the Director requires a well to be shut in because it did not connect to a gathering line or otherwise put natural gas to beneficial use as required by the approved gas capture plan. However, to prevent waste and protect public health, safety, welfare, the environment, and wildlife resources, the well must remain shut in until the Commission's hearing occurs.

Rule 904.

The Commission adopted a new Rule 904 to implement its obligation under Senate Bill 19-181 to evaluate cumulative impacts. Specifically, Senate Bill 19-181 requires the Commission to, "[i]n consultation with the department of public health and environment, evaluate and address the potential cumulative impacts of oil and gas development." C.R.S. § 34-60-106(11)(c)(II). Numerous Rules adopted or revised by the Commission in the 200–600 and 800/900/1200 Mission Change Rulemakings implement the Commission's statutory obligation to evaluate and address cumulative impacts, including Rules 303, 304, 314, 423, 424, 426, and 427. However, in consultation with CDPHE, the Commission determined that further evaluation of cumulative impacts of oil and gas development would be particularly valuable for both agencies. Although there is a great deal of information already available from many sources about air and climate impacts of oil and gas development in Colorado from individual sources, and some information about cumulative impacts, the Commission determined that additional studies and evaluation are necessary to adopt appropriately tailored regulations to address those cumulative impacts.

Rule 904.a

The purpose of Rule 904.a is to ensure that the Commission remains informed about ongoing evaluations of adverse impacts of oil and gas operations that are already underway pursuant to the Commission's 300 Series Rules, various AQCC regulations, efforts by other agencies, research by academic institutions, and innovative technologies developed by operators or other companies. Rule 904.a therefore requires the Director to make an annual report to the Commission, based on consultation with CDPHE and the Department of Natural Resources, including CPW, about a wide range of information.

First, a report about data gathered through the Commission's own Cumulative Impacts Data Evaluation Repository ("CIDER"). Annual review of this data will allow the Commission and its Staff to evaluate cumulative impacts to multiple categories of resources. The CIDER database encompasses not only estimates of reasonably foreseeable future impacts estimated for new oil and gas development, but also descriptions of existing impacts in areas near proposed development. This reflects the Commission's intent that evaluations of cumulative impacts encompass both new and existing impacts. Additionally, the Commission intends for the report on the CIDER database to encompass specific information about impacts to wildlife resources, including high priority habitat, and about water quantity. The Commission intends for the report to compare estimated quantities of water use reported pursuant to Rules 303.a.(5).B.iii.ee and 304.c.(18) with reports of actual water volume used pursuant to Rule 431.b. This evaluation of water quantity impacts will aid in the Commission's ongoing efforts to further incentivize water reuse and recycling.

Second, a report about the current status of the AQCC's Greenhouse Gas Pollution Reduction Roadmap, which includes targeted emissions reductions for the oil and gas sector. The report will also include updates about initiatives developed by the AQCC and APCD to achieve Colorado's statewide greenhouse gas emissions reduction targets set by House Bill 19-1261.

Third, a report about data reported to the AQCC's various oil and natural gas emissions inventories, which reflect actual emissions (as opposed to the Commission's CIDER database, which will reflect estimated emissions).

Fourth, information about the role of the oil and gas sector in making progress towards ambient air quality standards for criteria pollutants under the federal Clean Air Act, including tropospheric ozone.

Fifth, information about new and innovative technological developments, including any technologies employed by operators as a best management practice or condition of approval, to reduce emissions or otherwise avoid, minimize, or mitigate cumulative adverse impacts. The Commission intends for the annual report to be an opportunity for operators and Staff to share best practices for emissions reductions and other strategies of impact reduction to keep the Commission apprised of cutting-edge technological development.

Sixth, reports, studies, or research published by academic institutions or other agencies that are relevant to avoiding, minimizing, and mitigating cumulative adverse impacts of oil and gas development. The Commission recognizes that a large volume of high-quality research is occurring at Colorado's academic institutions, as well as federal agencies with research arms in Colorado. Additionally, substantial research is occurring nationwide and worldwide into technologies and practices to reduce the public health and environmental impacts of oil and gas development. The Commission intends for the annual report to provide an opportunity for it to be brought up to date on recent relevant research that may influence decisions made by the Commission throughout the rest of the year.

Seventh, the report may include any additional information requested by the Commission or that the Director believes is relevant. The Commission does not intend to limit the annual report to the six specifically enumerated categories of information about cumulative impacts and methods to address them.

If the information presented in the report indicates that a rulemaking to address cumulative impacts to any resource is warranted, that guidance should be issued, that a working group should be convened, or that a study should be conducted, then Rule 904.a.(8) authorizes the Director to propose such a rulemaking, guidance, working group, or study to the Commission as part of making the annual report. The Director or Commission may also propose additional studies related to the topics presented, as part of or in response to the annual report.

Rule 904.b

One barrier to successful evaluations of cumulative impacts in the past has been challenges with securing voluntary operator participation in the studies. Accordingly, in Rule 904.b, the Commission clarified its authority to require operators to participate in studies evaluating cumulative impacts as a condition of approval on an oil and gas development plan pursuant to Rule 307.b.(1). The Commission recognizes the value of studies to specifically evaluate cumulative greenhouse gas and hazardous air pollutant emissions, as well as monitoring techniques to measure cumulative hazardous air pollutant emissions. However, the Commission does not intend to limit the evaluation of cumulative impacts to solely these subjects, and accordingly did not enumerate the subject matter of studies that may be conducted pursuant to Rule 904.b.

The Commission anticipates that the studies evaluating cumulative impacts pursuant to Rule 904.b will be conducted as a cooperative effort by the Commission's Staff, CDPHE, CPW, the Public Utilities Commission ("PUC"), the Colorado Energy Office, operators, and experts from the academic, consultant, and non-governmental organization communities. The Commission anticipates receiving reports about the studies when they are complete, and may choose to take further regulatory action to address any cumulative impacts identified by the studies as appropriate at a later date.

The Commission intends that operators will only be required to participate in a study pursuant to Rule 904.b if the study is related to an oil and gas location proposed as part of an oil and gas development plan, or its impacts. In many cases, this will mean that there a proposed oil and gas location is in geographic proximity to an area relevant to the study. For example, a study might examine impacts on wildlife throughout a specific basin. However, the study might also consider the impacts of the proposed oil and gas location, which could include emissions that travel a long distance in the atmosphere, such as greenhouse gases or ozone precursors. As specified in Rule 904.b.(2), participation in a study does not mean providing funding (unless an operator chooses to do so voluntarily), but would include providing data, conducting investigations, performing monitoring, or otherwise gathering data which would be supplied to the Director. This may involve allowing the Commission Staff to access a physical location to gather data.

The Commission intends for the conditions of approval to potentially require operators to participate in studies that the Commission conducts in concert with third party organizations. If such a third party will be involved, then the Commission intends for the authorized third parties to be identified specifically as part of a condition of approval of an oil and gas development plan, which will include information such as a timeline for the third party to potentially access a location, the identity of the specific person(s) who would come on site, and the purpose for which that access would be authorized. The Commission does not intend to grant blanket permission for third parties to enter a site. The Commission recognizes that any third party accessing an oil and gas location would need to comply with appropriate safety training procedures and notify the operator prior to site visits. Site access would be appropriately controlled for purposes of safety. Such conditions of approval would be decided upon by the Commission in a hearing on a proposed oil and gas development plan. If an operator objects to any condition of approval allowing a third party to access an oil and gas location for purposes of conducting a study, the operator could raise such an objection at the hearing.

Rule 904.c

Because Senate Bill 19-181 creates a full-time Commission, the Commission recognizes that it may need an opportunity to gather information to evaluate and address the cumulative impacts of oil and gas development outside of the annual report provided by Rule 904.a. Accordingly, the Commission adopted Rule 904.c, which allows the Commission to convene an informational docket to gather information on a salient topic pursuant to its own motion. The informational docket will allow the Commission to solicit information that is reasonable and necessary to evaluate and address cumulative impacts. The Commission intends to model the informational docket after similar practices conducted by the PUC, which is also a full-time body.

Rule 905.

Consistent with its efforts to reorganize its 900 Series Rules into a more sequential order, the Commission moved prior Rule 907, which provides general requirements for management of E&P Waste, to Rule 905.

Several stakeholders suggested that the Commission adopt standards in Rule 905 allowing for risk-based E&P Waste management strategies. The Commission did build some risk-based standards into its revised 900 Series Rules. These include the distinct cleanup concentrations for contaminants that pose risks to residential soils and groundwater in Rule 915.a and Table 915-1, and the option for operators to request alternative remediation standards in Rule 913.h.(2) by submitting a formal variance request pursuant to Rule 502. However, the Commission determined that there are a sufficient number of complex technical, scientific, and policy questions inherent in adopting a risk-based strategy that it would be wiser to address those questions in a potential future dedicated rulemaking effort, rather than as part of the 800/900/1200 Mission Change Rulemaking.

Some stakeholders also suggested that the Commission create a system to fully document the composition and other characteristics of all E&P Waste. The Commission did not adopt this suggestion because many 900 Series Rules already require characterization and analysis of E&P Waste. Specifically, Rule 909.j.(1) requires operators to create profiles of the characteristics of produced water. Rule 913.b.(2).A requires operators to profile impacted media and waste in the course of remediation projects. Additionally, several 800 Series Rules, including Rules 805, 806, and 807 require analysis of injection fluids. While none of these Rules would necessarily require characterization of waste that is disposed of off-site, for example at a landfill, even though E&P Waste is classified as "exempt waste" under some state and federal laws, it still must meet the requirements of the receiving facility pursuant to Rule 905.b.(1). Many receiving facilities require waste profiling, and thus waste that is transported offsite to many commercial landfills is also subject to characterization requirements.

Rule 905.a

Rule 905.a.(1)

The Commission changed the language of Rule 905.a.(1) to match Senate Bill 19-181's revisions to the definition of "minimize adverse impacts," and updating the incorporation by reference of WQCC Regulation 41 to match the updated incorporation by reference in Rule 901.b. The Commission also added a reference to radiation control standards, in recognition of the Board of Health's recent rulemaking related to Technologically Enhanced Naturally Occurring Radioactive Material ("TENORM").

Some stakeholders raised questions about the use of the term "threatened" in Rule 905.a.(1). The Commission did not revise that term, which was also used in prior Rule 907.a.(1). In the Commission's experience, it is important for Rule 907.a.(1) to include threatened adverse environmental impacts, to ensure that operators take precautions to prevent E&P Waste from escaping appropriate storage confines. Prevention and avoiding impacts is especially crucial with respect to E&P Waste because until subsequent investigations occur, which may not take place for a lengthy period of time, it is not always clear whether contamination has occurred as a result of E&P Waste escaping from appropriate storage confines.

Rule 905.a.(2)

The Commission reworded Rule 905.a.(2) to improve clarity but did not make substantive revisions to the Rule.

Rule 905.a.(3)

The Commission broke the criteria for E&P Waste reuse and recycling plans in Rule 905.a.(3) into subsections to improve clarity. The Commission also added five criteria: final disposition of the waste, a proposed timeline for reuse and recycling, an explanation of the planned beneficial use, anticipated method of transporting the waste, and any additional information requested by the Director. The Commission made a conforming edit to Rule 304.c.(18).C to similarly require information on the anticipated method of transporting recycled or reused produced water on the water plan submitted with a Form 2A. The Commission added these criteria to facilitate its purpose of encouraging the reuse and recycling of E&P Waste, including produced water, and to ensure that beneficial use plans legitimately describe a use that provides public health, safety, welfare, or environmental benefits rather than simply realizing a financial incentive for the operator. Reuse and recycling of produced water is crucial in Colorado, and particularly on the Western Slope, because of the state's limited water supply and arid climate. It has numerous benefits for operators, water rights owners, agricultural interests, ecosystems, and wildlife. The Director remains committed to working with operators to facilitate the beneficial reuse and recycling of produced water. The Commission recognizes that reuse and recycling of produced water is especially beneficial when the produced water is transported by pipeline, rather than by truck, because minimizing truck traffic has benefits for public safety (avoided accidents), public health (avoided emissions), and wildlife (avoided collisions).

Some stakeholders requested that the Commission make submission of E&P Waste reuse and recycling plans mandatory rather than optional. The Commission determined that requiring reuse and recycling of E&P Waste in every case is not necessary at this time, and would potentially be inconsistent with the Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), because there are some cases where the environmental impacts that can result from treatment, storage, and conveyance of E&P Waste for reuse and recycling may be greater than not reusing and recycling such waste. However, pursuant to Rules 304.c.(11) and 905.a.(4), the Commission requires all operators to submit waste management plans with their oil and gas development plans. This will provide a further opportunity for the Commission's Staff to work with operators to encourage reuse and recycling of produced water, which is already becoming an increasingly common practice among Colorado's operators.

Several stakeholders raised questions about one of the criteria in Rule 905.a.(3).D, product quality assurance, that also appeared in prior Rule 907.a.(3). The Commission and operators have successfully implemented this standard for several years in the context of reuse and recycling plans to address the types of quantitative testing necessary in the E&P Waste recycling process. However, the Commission revised the language of this criterion to instead say "recycled materials quality assurance" to better reflect the intent of the Rule.

Other stakeholders raised questions about one of the new criteria, final disposition of the waste, in Rule 905.a.(3).E. Although the Commission added this criterion to the list of information on a reuse and recycling plan in the 800/900/1200 Mission Change

Rulemaking, the Commission already required this information to be submitted for reuse and recycling plans at centralized E&P Waste management facilities under prior Rule 908.b.(8).J. Based on the Commission's experience with obtaining this information for centralized E&P Waste management facilities, the Commission determined that it is important for its Staff to have this information to evaluate reuse and recycling plans in order to track information about produced water form cradle to grave. The criterion does not require an operator to adhere to any specific final disposition for the E&P Waste, but rather identify whether the operator plans to dispose of it in a cuttings trench, landfill, injection well, or some other method. Final disposition is also important information for wastes derived from treatment processes such as brines or solids generated from produced water treatment.

Rule 905.a.(4)

The Commission adopted a new Rule 905.a.(4) requiring all operators that generate E&P Waste to submit a comprehensive waste management plan as an attachment to their Form 2As pursuant to Rule 304.c.(11). Under the Commission's prior Rules, waste management plans were only required for oil and gas locations within 1,000 feet of a building unit pursuant to Rule 303.b.(3).J.ii and for operations in the Greater Wattenberg Area pursuant to prior Rule 318A.i. The change to requiring waste management plans for all new oil and gas operations statewide is consistent with the Commission's overall approach of encouraging additional consideration of strategies to minimize adverse environmental impacts through the permitting process, which affords the Commission's Staff and the Commission itself greater opportunity to work with operators to develop successful plans to avoid, minimize, and mitigate impacts prior to the impacts occurring. The Commission's enforcement experience has shown that operators who generate E&P Waste without first developing a management plan for those wastes are more likely to violate the Commission's Rules. Operators will not be required to submit waste management plans for existing oil and gas locations, unless the operator proposes a significant modification that requires submission of a new or revised Form 2A. However, the Commission does not intend for operators to be required to submit a waste management plan for existing operations when the operator is required to submit a Form 27. The Commission instructs its Staff to issue guidance on the required contents of a waste management plan.

One required component of the waste management plan is an evaluation of opportunities for reusing and recycling water. The Commission strongly encourages operators to reuse and recycle water whenever possible. The waste management plan therefore provides an opportunity for the Commission's Staff to work with an operator to identify any possible opportunities for recycling and reusing water that may have been overlooked, in concert with review of the water plan pursuant to Rule 304.c.(18). If an operator already intends to recycle or reuse water, they may submit a reuse and recycling plan pursuant to Rule 903.a.(3) as part of their Form 2A application for a new oil and gas location.

Because one impact of E&P Waste management may be truck traffic to haul away waste, the Commission specified that the Director may require waste management plans to include descriptions of proposed haul routes, including the operator's plans for adhering to any applicable local government traffic requirements. The Commission instructs its Staff to specifically address alternative waste removal strategies, such as when off-location flowlines are used to transport E&P Waste, in the guidance it issues to operators about compliance with Rule 905.a.(4). The Commission also instructs its Staff to address what changes to waste management plans require submitting revised waste management plans pursuant to Rule 905.a.(4).C. The Commission intends for this requirement to be consistent with the significant/insignificant dichotomy encapsulated by Rule 404, governing Form 4s.

Rule 905.a.(5)

The Commission adopted a new Rule 905.a.(5) to clarify procedures for requiring investigation of unexpected E&P Waste that is discovered at active locations and at locations where a prior remediation project was completed and closed, or where historic impacts are discovered at closed oil and gas locations. Confusion has arisen in the past about the Commission's authority to require investigation of unexpectedly-discovered waste at locations that were subject to a prior, closed remediation project and at closed locations. In Rule 905.a.(5), the Commission clearly delegated this authority to the Director to alleviate confusion. Rule 905.a.(5) codifies a condition of approval which is routinely placed on Form 27s when the Director grants closure of a remediation project based on the information provided by the operator relative to the investigation and work conducted.

Some stakeholders suggested that Rule 905.a.(5) violates the responsible party provisions of the Act. C.R.S. §§ 34-60-124(6)(b) & (7). The Commission does not agree with those stakeholders because Rule 905.a.(5) is intended to constitute a responsible party determination. Rule 905.a.(5) provides that the Director may order an operator to conduct an investigation, but only if the Director has evidence to determine that the operator's conduct may adversely impact public health, safety, welfare, the environment, or wildlife resources. Thus, Rule 905.a.(5) effectively requires the Director to make an evidence-based determination that an operator has violated the Act, C.R.S. § 34-60-106(2.5)(a), prior to ordering the operator to conduct an investigation. The Act defines a responsible party as an operator who conducts an activity that, among other things, violates the Act. C.R.S. § 34-60-124(8). Even though Rule 905.a.(5) is not a formal enforcement action, operators who wish to raise an affirmative defense that another party is the responsible party for the potential contamination that the Director requires to be investigated may seek the Commission's review of the Director's responsible party determination by filing an application pursuant to Rule 503.g.(10), and under the provisions of Rule 526.
Some stakeholders suggested adding a provision to Rule 905.a.(5) to address the investigation of contaminants that pose unacceptable risks, but are not currently

subject to applicable standards. The Commission did not adopt this suggestion because in general, the WQCC Regulation 41 narrative standards for protection of groundwater that are incorporated by reference throughout the 900 Series provide an adequate basis to address this category of contaminant.

Rule 905.b

The Commission moved prior Rule 907.b, governing E&P Waste transportation, to Rule 905.b. The Commission made several minor wording changes to prior Rule 907.b.(1) to improve clarity and separated prior Rule 907.b.(1) into two subsections to provide further clarity. In Rule 905.b.(1), the Commission also specified the potential off-site facilities where waste may be transported, which include permitted commercial waste disposal facilities, commercial waste recycling facilities, and beneficial use sites. The Commission clarified that such sites must be properly permitted by both CDPHE and the relevant local government.

In Rule 905.b.(2), the Commission added a standard that operators must adhere to the Rocky Mountain Low-level Radioactive Waste Board's ("RMLLRWB") rules, which govern interstate transport of radioactive waste. The Commission also incorporated those Rules by reference in Rule 902.b.(3).J. Although the obligation to comply with the RMLLRWB's rules exists independent of the Commission's Rules, the Commission determined that it would provide a valuable reminder to operators of this obligation to incorporate the standard into the Commission's Rules.

Some stakeholders raised questions about whether operators will be required to adhere to waste disposal regulations promulgated by CDPHE and local governments. Rules 905.b.(1) and (2) are intended to remind operators of their obligation, which exists independent of the Commission's Rules, to adhere to CDPHE and local government requirements, including requirements promulgated by local governments or other states when waste is transported between states.

Other stakeholders raised questions about the meaning of the term "authorized by the Director" in Rule 905.b.(1). As with the same language in prior Rule 907.b.(1), the Commission intends this to be a reference to centralized E&P Waste management facilities, which are a category of waste disposal locations that are subject to the Commission's and Director's permitting authority.

Other stakeholders questioned the legality of Rule 905.b.(2), because it discusses activities that occur outside of Colorado. Rule 905.b.(2) is substantively unchanged from the Commission's prior Rule 907.b.(1). The Commission believes that both Rules fully comply with its statutory authority, because they do not impose substantive requirement for activities outside of Colorado, but rather remind operators of their independent obligation to adhere to regulatory requirements in other states.

The Commission moved prior Rule 907.b.(2), establishing requirements for waste generators, to Rule 905.b.(3), and reworded and reorganized the Rule for clarity, but did not substantively revise it. Some stakeholders raised questions about Rule 905.b.(3).E, which requires operators that generate E&P Waste to maintain records of the type and volume of waste transported. This is identical to prior Rule 907.b.(2).E. The Commission has authority to require this information to be maintained because, although E&P Waste is exempt from the federal Resource Conservation and Recovery Act ("RCRA"), it nevertheless must meet the requirements for disposal at the receiving facility, which may include standards for toxicity, reactivity, corrosivity, or other properties. *See generally* 40 C.F.R. §§ 261.20–24. If the E&P Waste does not meet that standard and would qualify as hazardous waste, then it must be taken to a facility licensed to receive such materials.

Rule 905.c

Rule 905.c.(1)

The Commission moved prior Rule 907.c, governing produced water, to Rule 905.c. In Rule 905.c.(1), the Commission made relatively minor changes to the wording of prior Rule 907.c.(1). The only substantive change the Commission made was to add the term "hydrocarbon sheen" to the list of substances that operators must prevent from entering produced water pits. Some stakeholders raised concerns about how operators would be able to quantitatively measure a sheen. The Commission intends for operators to comply with, and for its Staff to enforce, this Rule based on the presence of a visible sheen in the produced water pit. If the sheen is visible to the naked eye, then it is a clear indicator that hydrocarbons are present and need to be removed.

Rule 905.c.(2)

The Commission moved prior Rule 907.c.(2) to Rule 905.c.(2) and made several changes to the Rule. In Rule 905.c.(2).A, the Commission updated the cross-reference to be consistent with the Commission moving its Rules governing Class II UIC wells to its 800 Series Rules, but did not make substantive changes.

Consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), the Commission revised Rule 905.c.(2).B to clarify that evaporation and percolation are only acceptable produced water disposal techniques at pits that are operated pursuant to the Commission's Rules in a manner that do not cause a violation of any applicable WQCC Regulation 41 numeric and narrative standards. The Commission revised the Rule based on both its statutory directive to prevent and minimize adverse impacts to the environment and water resources, *see* C.R.S. § 34-60-106(2.5)(a), and its statutory obligation as a groundwater protection implementing agency, *see id.* § 25-8-202(7)(a). Although new percolation pits are not permitted pursuant to Rule 910.a, which requires all new pits to be lined, the Commission intends for its Staff to continue their current practice of ensuring that fluids discharged into existing percolation pits cannot reach groundwater in a manner that would violate WQCC groundwater classifications and standards.

Some stakeholders raised questions about the meaning of "properly permitted." The Commission used this language because some pits that existed prior to 1998 were only registered with the Commission, but were never permitted by the Commission. The Commission only intends to allow produced water evaporation at pits subject to more recent permitting requirements, because earlier pits that are registered but not properly permitted would not always have been constructed with appropriate safeguards.

Other stakeholders questioned why the Commission continues to allow pits to be used for produced water disposal. The Commission determined that the changes it made throughout the 200–600 Mission Change Rulemaking and 800/900/1200 Mission Change Rulemaking, including requiring secondary containment in its 600 Series Rules and several changes throughout its 900 Series Rules ensures the environmental safety of pits when they are used for a limited number of remaining purposes.

Other stakeholders raised questions about the use of evaporation pits on surface locations where a surface owner has not consented to a pit. The Commission does not believe that additional provisions are necessary to ensure surface owner protection in Rule 905.c.(2).B, particularly because changes in the Commission's 300 Series Rules, including requiring alternative location analyses in Rule 304.b.(2).B.ix for proposed oil and gas locations subject to surface owner protection bonds pursuant to Rule 703, provide adequate protections for surface owners.

Finally, some stakeholders suggested adding resources and media beyond groundwater to the list of adverse impacts that must be prevented in Rule 905.c.(2).B. The Commission did not add additional media or resources to the list because impacts to other resources, such as public health, safety, welfare, the environment, and wildlife resources will be addressed during the permitting process governed by the Commission's 300 Series Rules.

Consistent with revisions to Rule 427, the Commission eliminated prior Rule 907.c.(2).D, which permitted disposal of produced water by roadspreading on lease roads outside of sensitive areas. The Commission determined that this disposal technique is not consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). Operators may propose alternate disposal methods such as road spreading through a waste management plan, which the Director may approve if such methods protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

The Commission moved prior Rule 907.c.(2).E to Rule 905.c.(2).D, and made minor clarifications to the wording, updated cross references, capitalized defined terms, and updated incorporations by reference. The Commission added a new criterion in Rule 905.c.(2).D.ii requiring that operators prevent adverse surface impacts such as erosion or contamination that can result from produced water flowing across the surface. Prior CDPHE permitted discharges that require the movement of fluids across the surface have resulted in erosion problems and harm to soil and vegetation, particularly in the Raton Basin and in Washington and Logan Counties. Accordingly, the Commission determined that it was necessary and reasonable to require operators to prevent adverse surface impacts as a component of CDPHE-permitted discharges.

Consistent with prior practice, if CDPHE permits discharge into any waters of the state, then CDPHE will include any necessary water monitoring requirements in the discharge permit. Therefore, the Commission did not adopt independent monitoring requirements in Rule 905.c.(2).D.

The Commission moved prior Rule 907.c.(2).F to Rule 905.c.(2).E and made non-substantive changes to the Rule.

Rule 905.c.(3)

Similarly, the Commission moved prior Rule 907.c.(3), governing produced water reuse and recycling, to Rule 905.c.(3) and clarified wording, updated cross-references, and capitalized defined terms, but did not make substantive changes. Numerous stakeholders provided general comments on the importance of encouraging or requiring operators to reuse and recycle water whenever possible. As discussed in the Commission's Statement of Basis and Purpose for Rules 304.c.(18), 431.b, 904.a, and 905.a.(3), the Commission adopted new measurement and reporting requirements for reused and recycled produced water. The information the Commission collects pursuant to Rule 431.b, coupled with the information the Commission receives through water plans submitted with oil and gas development plan applications pursuant to Rule 304.c.(18), will provide the Commission with a clearer evidentiary basis with respect to whether to adopt additional standards for produced water reuse and recycling in the future. For this reason, the Commission did not adopt the change suggested by some stakeholders to make Rule 905.c.(3) mandatory, rather than optional. The Commission believes that it is more appropriate to encourage the reuse and recycling of produced water to the maximum extent possible but does not believe it is appropriate to require it in all situations.
Other stakeholders questioned the meaning of the phrase "other approved uses." The Commission intends this phrase to be a reference to any other reuse of produced

water for oil and gas operations approved by the Commission on a waste management plan.

Rule 905.c.(4)

The Commission moved prior Rule 907.c.(4) to Rule 905.c.(4) but did not make substantive changes to the Rule.

Rule 905.c.(5)

The Commission adopted a new Rule 905.c.(5), governing water sharing agreements. The Commission instructs its Staff to update the Commission's existing water sharing guidance to reflect the changes in the 800/900/1200 Mission Change Rulemaking. Some stakeholders raised concerns about the confidentiality of information submitted in a water sharing agreement. The Commission's Staff will treat any confidential information submitted as confidential pursuant to Rule 223 and will not disclose that information to the public. The purpose of requiring operators to submit agreements is to allow the Commission's Staff to track produced water from cradle to grave, not to disclose confidential business information. Some stakeholders also suggested a shorter submission timeframe than 60 days prior to the implementation of the water sharing plan. Although the Commission recognizes the importance of flexibility in the course of negotiating a water sharing agreement, the Commission determined that 60 days is necessary for its Staff to fully review a proposed water sharing agreement. An operator that seeks to make a change to a submitted or approved water sharing agreement within the 60 day window may submit a Form 4 prior to initiating the water sharing process to request the Director's approval for any subsequent changes.

Rule 905.d

The Commission moved prior Rule 907.d, governing drilling fluids, to Rule 905.d. The Commission did not make substantive changes to Rule 905.d.(1), except to specify that drilling pits must be properly permitted and operated pursuant to Rules 908, 909, and 910.

Similarly, the Commission moved prior Rule 907.d.(2) to Rule 905.d.(2) and made non-substantive revisions to clarify the wording, update cross references, and capitalize defined terms.

However, the Commission revised the definition of two terms used in Rule 905.d.(2), Land Application and Land Treatment. The Commission removed the word "sometimes" from the definition of Land Application, and changed the word "or" to "and" to clarify that land application always requires incorporating treated E&P Waste into soils, rather than solely spreading the material upon the soil. In the definition of Land Treatment, the Commission changed the phrase "is applied to soils and treated" to instead say "is treated ex situ at the land surface." This serves to clarify the distinction between Land Application and Land Treatment. The Commission also changed the "and" in the second sentence of the Land Treatment definition to be an "or" to indicate that the enhancement methods listed need not all be used in every circumstance. The Commission intends for the word "treated" in the definition of land application to signal compliance with Table 915-1 standards, which will generally require treatment, but may not require treatment if an operator demonstrates that materials being incorporated already comply with Table 915-1 without requiring treatment.

The Commission moved prior Rule 907.d.(3), governing disposal of water-based bentonitic drilling fluids, to Rule 905.d.(3). The Commission added an additional criterion to the disposal methods listed in Rule 905.d.(3).A, drying and burial in pits on non-crop land, which is that the Director approves the operator's plan for closing the pit pursuant to a Form 27. Unlike produced water disposal, the Commission does not believe that a surface use agreement is warranted for disposal of water-based bentonitic drilling fluids because of the very low degree of contamination associated with water-based bentonitic drilling fluids, the lower volume of drilling fluids compared to produced water, and safeguards in the Commission's Rules to ensure the appropriate closure of pits.

Some stakeholders raised questions about which standards in Table 915-1 will apply to the disposal of water-based bentonitic drilling fluids in pits. The Commission anticipates that in most circumstances, the residential soil screening levels will apply, but in areas where land application occurs above shallow groundwater, the Director may require compliance with Table 915-1's standards for protection of groundwater. Consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), in Rule 905.d.(3).B, the Commission made seven revisions to the standards for land application provided by prior Rule 907.d.(3).B to better minimize adverse environmental impacts, and to clarify areas that had created confusion for operators in the past.

First, consistent with the broader waste management plan requirements of Rule 905.a.(4), the Commission required land application of water-based bentonitic drilling fluids to be approved in a waste management plan.

Second, the Commission clarified that operators must incorporate the drilling fluid waste into the uppermost soil horizon. Although incorporation was already required under the Commission's prior Rules, some operators had previously indicated confusion as to whether it was required.

Third, consistent with the Commission's 1000 Series Rules, the Commission prohibited application of water-based bentonitic drilling fluids on non-crop lands.

The Commission only intends land application to be conducted on cropland, because the Commission determined that only croplands, which undergo routine mixing of the uppermost soil horizon during tilling, planting, and harvesting, realize actual benefits from the application of water-based bentonitic drilling fluids by enhancing the moisture holding capacity of the soil. In the past, operators have applied drilling fluids to rangelands, and then been required to reclaim areas that otherwise would not have been subject to reclamation requirements, because no actual benefit was realized by the application of the waste material to otherwise undisturbed land. Accordingly, the Commission clarified in its Rules that operators may only conduct land application as a beneficial soil amendment on croplands, and may not do so on non-crop lands.

Fourth, the Commission clarified that operators must analyze water-based bentonitic fluids for contaminants of concern and provide the results of this sampling and analysis to the Director upon request.

Fifth, the Commission provided operators must obtain approval for land application from relevant local governments, where applicable.

Sixth, the Commission specified that operators must submit the surface owner's written authorization for the land application to the Director upon request, to provide the Director with a better means of enforcing violations of the surface owner consent requirement.

Seventh, the Commission provided additional specificity about the duration, submission timeline, and substantive requirements for recordkeeping. The Commission determined that these changes will provide clearer, stronger, and more enforceable protections for the environment, especially in agricultural areas where water-based bentonitic drilling fluids may still permissibly be disposed of via land application. The Commission recognizes that these regulatory changes may result in less water-based bentonitic drilling fluids being managed through land application, which may result in increased truck traffic for disposal at commercial facilities. However, the Commission determined that any potential adverse environmental impacts associated with increased truck traffic will not outweigh the environmental benefits of requiring waste to be treated to Table 915-1 standards prior to land application. These changes will prevent contamination and remediation issues that have arisen from improper land application of drilling fluids in the past, which resulted in substantial costs to operators and surface owners, and time investment by the Commission's Environmental Protection Specialists. Lacking the clarity provided by proposed Rule 905.d.(3).B, in the past, in some cases land application resulted in exceedances of prior Table 910-1 standards after application of cuttings or bentonitic fluids, which then required additional remediation projects to address the introduction of contaminants. Accordingly, the Commission determined that it is more consistent with the Commission's statutory directive to protect and minimize adverse impacts to the environment to require compliance with the Table 915-1 cleanup standards *before* waste is applied. *See* C.R.S. § 34-60-106(2.5)(a). The Commission therefore determined that the revised Rule 905.d.(3).B provides necessary and reasonable environmental safeguards that will allow land application of water-based bentonitic drilling fluids where appropriate and require alternate disposal mechanisms in other circumstances.

Rule 905.e

The Commission moved prior Rule 907.e, governing oily waste, to Rule 905.e. The Commission moved the definition of Oily Waste, which was included in prior Rule 907.e, to its 100 Series Definitions, and also modified the definition. First, the Commission added a quantifiable standard that Oily Waste includes only materials containing unrefined petroleum hydrocarbons in excess of concentrations permitted by Table 915-1. This objective standard will make it easier for both the Commission's Staff and operators to identify what materials constitute Oily Waste. Second, the Commission added cuttings to the definition. Some stakeholders raised questions about whether oil-based mud would be considered Oily Waste. Consistent with its prior practices, the Commission will continue to consider oil-based muds and cuttings generated using oil-based muds to be Oily Waste.

Several stakeholders suggested that the Commission eliminate the option for onsite land treatment of oily waste, which was permitted by prior Rule 907.e.(1).B and remains an option pursuant to Rule 905.e.(1).B. The Commission did not adopt these stakeholders' suggestion. Land treatment is a common method for treating oily waste. Accordingly, the Commission determined that it is important to provide clear standards to ensure that land treatment of oily waste is conducted safely and without environmental contamination, which the Commission provided in Rule 905.e.(2). The Commission acknowledges that many operators have shifted their practices towards off-site disposal of oily waste at centralized E&P Waste management facilities or commercial disposal facilities. However, the Commission determined that it is important to continue the option of onsite treatment of oily waste, subject to robust environmental protections, because at locations that are located at greater distances from commercial disposal facilities and centralized E&P Waste management facilities, the environmental impacts of increased truck trips to transport the waste offsite may outweigh the environmental benefits of avoiding onsite land treatment. Thus, the Commission determined that it was appropriate to continue to allow onsite land treatment of oily waste, but simultaneously strengthened the Commission's oversight and substantive standards to ensure that it is conducted in an environmentally protective manner. The Commission encourages operators to minimize emissions from land treatment operations by using best management practices which may include but are not limited to incorporating compost, mulch, or other soil amendments as a cap to the land treatment.

Stakeholders also questioned whether off-site land treatment of oily waste at centralized E&P Waste management facilities, which is permitted by Rule 905.e.(1).C, is appropriate. The Commission determined that this is an appropriate practice when conducted pursuant to the environmental safeguards in the Commission's Rules. Additionally, it is a relatively rare practice. There are approximately 50 currently active centralized E&P Waste management facilities in Colorado, and less than ten are specifically permitted to allow for land treatment of oily waste. The limited scope of this activity allows the Commission's Staff to provide robust oversight. Other stakeholders requested that the Commission specify that any off-site transport of E&P waste, including oily waste, to centralized E&P Waste management facilities only be permitted if the facilities were "in compliance with the Commission's Rules." The Commission did not adopt this requirement because it expects all facilities it regulates to fully comply with its Rules. However, the Commission also recognizes that not all violations of its Rules would necessarily compromise the safety of waste disposal at a facility. For example, an operator's failure to timely submit a required form should not necessarily preclude the facility from accepting E&P Waste. The Commission will continue to exercise its enforcement discretion to appropriately address non-compliance with the Commission's Rules by centralized E&P Waste management facilities on a case-by-case basis.

In Rule 905.e.(1).D, the Commission added a new option for operators to propose an alternative method for on-site treatment oily waste other than tank bottoms on Form 27 applications. This option will allow operators to adjust E&P Waste management practices on a case-by-case basis, while still ensuring that the Commission's Staff has adequate oversight to ensure that all practices for treating and disposing of oily waste are safe and protective of the environment. Some stakeholders requested that affirmative surface owner consent be required for alternate methods of onsite treatment of oily waste. The Commission did not adopt this requirement because any form of onsite treatment would only be permissible if authorized by a surface use agreement, so separate surface owner consent would only be necessary for offsite treatment options.

Consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), the Commission clarified and strengthened its standards for land treatment of oily waste in Rule 905.e.(2) in seven ways. First, the Commission provided clearer minimum standards for Form 27s seeking approval for onsite land treatment of oily waste in Rule 905.e.(2).A.

Second, in Rule 905.e.(2).E, the Commission strengthened and clarified its standards for protecting groundwater and surface water in the course of land treatment of oily waste. Specifically, the Commission changed the term "contamination" to the defined term "Pollution," which better encapsulates the Commission's intent that operators conduct land treatment of oily waste in a manner that does not violate any WQCC standards or classifications. The Commission also adopted several subsections to the Rule to better clarify the procedures and conditions of approval that its Staff have previously employed to protect groundwater and surface water in the course of land treatment activities. First, the Commission required the use of best management practices to ensure that stormwater does not leave the land treatment area, as stormwater discharge could carry contamination off-site. Second, the Commission specified that land treatment areas should be evaluated based on contaminant mobility, soil type, and the depth to groundwater to avoid any potential for contaminants to migrate into groundwater, in potential violation of WQCC regulations. Third, the Commission specified that land treatment areas must be at least 200 feet away from surface water bodies to avoid potential spills and releases or contaminant migration into those water bodies. This is not intended to limit the Director's ability to require a land treatment area to be established farther from surface water if topography, soil type, vegetation type, or waste properties would increase the risk of causing pollution to the surface water. Finally, to further protect groundwater, the Commission provided that the Director may require the use of a liner beneath the land treatment area on a case-by-case basis, as appropriate. The Commission does not believe that a liner is appropriate in every circumstance, because it may create additional waste that must be remediated and reclaimed after land treatment has been completed.

Third, in Rule 905.e.(2).F, the Commission made standards for enhancing biodegradation mandatory, and required operators to seek approval for a specific frequency of various biodegradation enhancement practices on their Form 27 applications. Stakeholders raised numerous questions about Rule 905.e.(2). Some stakeholders questioned whether the "other amendments" to enhance biodegradation listed in Rule 905.e.(2).F include chemical oxidation. The Commission does not consider chemical oxidation to be a form of biodegradation, but operators may seek approval to use chemical oxidation methods or other alternative treatment methods on their Form 27 remediation plans pursuant to Rules 905.e.(1).D and 905.e.(2).A.

Fourth, in Rule 905.e.(2).G, the Commission clarified that the Table 915-1 standards for inorganic constituents and metals apply. Some stakeholders suggested that the changes to Rule 905.e.(2).G might limit operators' ability to beneficially reuse or incorporate treated oily waste. The Commission does not share this concern because Rule 905.e.(2).G requiring compliance with Table 915-1 is necessary for the Commission's Staff to be able to ensure that treated oily waste is used appropriately and safely. Operators may work with the Commission's Staff through the Form 27 approval process to ensure that beneficial reuse is not unduly limited. The Commission determined that Rule 905.e.(2).G is necessary to prevent ongoing residual impacts from treated waste other than organic constituent, recognizing that metals may also have unintended adverse environmental impacts. Stakeholders also questioned whether the residential soil screening levels or protection of groundwater soil screening levels in Table 915-1 would be applied in Rule 905.e.(2).G. Consistent with its practice throughout the 900 Series Rules, the Commission will apply the residential soil screening levels unless there is a risk to groundwater.

Fifth, in Rule 905.e.(2).H, the Commission clarified and strengthened requirements for surface owner consent to ensure that surface owners clearly authorize onsite land treatment in any area not being utilized for oil and gas operations, and provide adequate notice to surface owners prior to commencing land treatment. Some stakeholders questioned the necessity of providing evidence of surface owner consent for offsite land treatment in Rule 905.e.(2).H. Because land treatment may significantly impact a surface owner's ability to use areas of their property, it is important for the Commission to be able to ensure that a surface owner is aware of, and has consented to, land treatment. This is particularly true for off-site land treatment contemplated by Rule 905.e.(2).H.i, which would involve spreading oily wastes on lands that were not previously disturbed by the oil and gas operations.

Sixth, in Rule 905.e.(2).J, the Commission prohibited land treatment after the final well at a location has been plugged. Some stakeholders questioned the necessity of adopting Rule 905.e.(1).J. The Commission adopted this requirement to ensure consistency with the timeline requirements of its 1000 Series Reclamation Rules. In the Commission's experience, a lack of clarity over this timeline has previously led to confusion for operators. The Commission intends that, once the final well at a location is plugged, the location moves into the reclamation phase, and therefore it is no longer appropriate to initiate on-site land treatment of oily waste through new remediation projects. The Commission intentionally used the word "final" in Rule 905.e.(1).J, in recognition that there may be locations where some, but not all, wells are plugged while other wells are still active. In the rare circumstances where land treatment of oily waste may still be appropriate at a location where all wells have been plugged, operators may request a variance pursuant to Rule 502.

Seventh, in Rule 905.e.(2).K, the Commission required operators to complete land treatment within three years. This codifies an existing practice of the Commission's Staff, who previously attached conditions of approval to Form 27s requiring land treatment operations to have a maximum 3-year duration. If operators do not complete land treatment within three years, then the operator must submit a Form 28, Centralized E&P Waste Management Facility Permit application to convert the location into a centralized E&P Waste management facility. The purpose of Rule 905.e.(2).K is to disincentivize long term on-site remediations, while also ensuring that if long-term on-site remediation projects do occur, they are subject to the more protective standards for centralized E&P Waste management facilities. The Commission acknowledges that the shorter warm season at higher elevations is a reason that land treatment may not be a preferable waste management option at higher elevations. Other waste management methods, including converting a site to a centralized E&P waste management facility, or off-site disposal, may be preferable at these locations. When land treatment is conducted at high-elevation locations, it will require careful planning with an aggressive schedule to routinely enhance biodegradation as required by Rule 905.e.(2).F during the warm season while continuing to perform required maintenance throughout the year. There are numerous open long-term on-site remediation projects in progress that currently require significant time investments by the Commission's Staff for oversight and result in ongoing adverse environmental impacts due to the slow pace of remediation. The Commission recognizes that the three-year limit may be challenging for operators to achieve in some circumstances. However, in such circumstances, Rule 905.e.(1) provides that there are at least three other options for remediation of oily waste, including off-site disposal. The Commission intends for on-site land treatment to only be used in the limited circumstances where soil conditions and other factors make bioremediation feasible, environmentally safe, and possible to complete within three years.

Rule 905.f

The Commission moved prior Rule 907.f, governing other E&P Waste, to Rule 905.f and made non-substantive revisions to clarify the wording, update cross references, and capitalize defined terms.

Rule 905.g

The Commission adopted a new Rule 905.g governing treatment and disposal of drill cuttings. The Commission determined that drill cuttings are an important category of E&P Waste, and that it is necessary to provide operators with clear standards for their treatment and disposal.

In Rule 905.g.(1), the Commission specified that drill cuttings containing oily waste must be managed as oily waste pursuant to Rule 905.e. This clarifies what has previously been a source of significant confusion for operators statewide. The Commission adopted Rule 905.g.(1) to clarify that all oily waste must be treated as oily waste because of its properties, regardless of whether the waste originates in drill cuttings or from another source. In circumstances where drill cuttings have not yet been sampled to determine their characteristics, the Commission intends for operators to assume that they are oily waste.

In Rule 905.g.(2), the Commission adopted standards for management of drill cuttings that are generated using water-based bentonitic drilling fluids, which are less likely to contain hazardous materials. This category of drill cuttings may be disposed of at a commercial solid waste facility, a centralized E&P Waste management facility, through land application in soil with surface owner approval, through on-location burial in a drilling pit, or burial in a cuttings trench. Some stakeholders questioned whether it would be possible to meet certain contaminant concentrations in Table 915-1 for cuttings generated using water-based bentonitic drilling fluids disposed of pursuant to Rule 905.g.(2). If drill cuttings do not comply with the standards in Table 915-1, they may require treatment and/or off-site disposal. The Commission also added a cross-reference to Rule 915.b to clarify that the Director must approve management of drill cuttings that exceed Table 915-1 standards for constituents listed in the soil suitability for reclamation section of Table 915-1.

Consistent with permitting drill cuttings containing water-based bentonitic fluids to be disposed of in a Cuttings Trench in Rule 905.g.(2).E, the Commission adopted a new definition of Cuttings Trench in its 100 Series Rules. This clarifies that a Cutting Trench is any depression or hole used for disposal or storage of dried cuttings that are generated during drilling a well. This resolves prior uncertainty about whether cuttings trenches would be treated differently than pits. The Commission does not intend for cuttings trenches to be used for disposal of materials that have hazardous properties. The Commission made conforming changes throughout its 900 Series Rules to ensure that the newly defined term Cuttings Trench is appropriately treated as a unique category of pits.

Rule 906.

The Commission moved prior Rule 907A, governing management of non-E&P Waste, to Rule 906. The purpose of Rule 906 is to ensure that operators are aware of their obligations to comply with waste disposal rules promulgated by CDPHE's Solid and Hazardous Waste Commission ("SHWC"), in addition to the Commission's E&P Waste management Rules in the 900 Series. The Commission formally incorporated the applicable SHWC Rules by reference in Rule 901.b to provide additional clarity and to facilitate operators locating the applicable regulation.

Consistent with changes the Commission made to Rule 606.d, in Rule 906.d, the Commission also prohibited the burning and burial of non-E&P Waste, including trash or other waste materials, at oil and gas locations.

Several stakeholders requested that the Commission adopt additional regulatory standards for the management and disposal of TENORM. Because Rule 906 requires operators to comply with the otherwise applicable regulations of other state agencies governing waste disposal, operators must adhere to other agency's standards for management and disposal of TENORM. The Board of Health conducted a rulemaking to adopt standards for managing TENORM concurrently with the 800/900/1200 Mission Change Rulemaking, and adopted its regulations just two days prior to the Commission's final vote to approve the 800/900/1200 Mission Change Rules. Accordingly, the Commission determined that it was inappropriate to adopt its own TENORM regulations, if any, prior to the Board of Health and HMWMD having time to implement their own regulations. However, the Commission added two isotopes of radium (^{226}Ra and ^{228}Ra) to the list of analytes that operators must analyze in produced water quality samples in Rule 909.j.(1).K, as well as injection formation and injection fluid samples required by Rules 803.g.(5).C & D, 803.h.(1), and 806.c. The Commission determined that this data is important to help characterize the presence of Natural Occurring Radioactive Material ("NORM") in produced water to provide a useful data foundation for both its own future regulatory efforts, and potentially also CDPHE's ongoing regulatory processes. As discussed below, the Commission specifically chose the isotopes that the Board of Health will use to determine if a waste falls under the newly-adopted TENORM regulations.

Rule 907.

Rule 907.a

The Commission moved prior Rule 908, governing centralized E&P Waste management facilities, to Rule 907. The Commission capitalized defined terms in Rule 907.a but did not make substantive changes to the Rule.

Rule 907.b

Consistent with changes made to the Commission's permitting process in its 300 Series Rules, the Commission made several changes to the permitting requirements for centralized E&P Waste management facilities in Rule 907.b. First, the Commission required that in addition to a Form 28, operators must also submit a Form 2A permit application for new centralized E&P Waste management facilities. Because centralized E&P Waste management facilities have substantial surface impacts, the Commission determined that it was important for them to undergo the same review as other surface disturbance that requires a Form 2A pursuant to Rule 304. The requirement for centralized E&P Waste management facilities to obtain Form 2A approval only applies to new facilities and is not retroactive. However, pursuant to Rules 301.c and 304.a.(3), operators will be required to submit a Form 2A for any significant modifications to existing centralized E&P Waste management facilities. Several stakeholders requested that the Commission add various notice and other provisions to the centralized E&P Waste management facility permitting process in Rule 907.b. However, centralized E&P Waste management facility applications will be subject to all procedural and substantive requirements that apply to all Form 2A applications pursuant to the Commission's 300 Series Rules, including notice, consultation, local government siting disposition, and public comment. To avoid unnecessary duplication, the Commission did not add these independent requirements to Rule 907.b. Consistent with Rule 803.b, the Commission specified that corresponding 300 Series permits must be submitted at the same time as the Form 28 application to appropriately align opportunities for notice and comment.

In Rules 907.b.(1)–(5), the Commission only made minor wording clarifications. The Commission only made three substantive changes. First, consistent with technological changes, the Commission required operators to provide email addresses on Form 28 applications in Rules 907.b.(1) and (2). Second, consistent with Senate Bill 19-181's changes to local government authority, the Commission moved prior Rule 908.h to Rule 907.b.(5).F, and required operators to provide evidence that they have complied with any relevant local government land use regulations and facility siting, operation, and construction requirements. Third, consistent with Senate Bill 19-181's changes to the Commission's statutory authority and mission, C.R.S. § 34-60-106(2.5)(a), and with Rule 604, in Rule 907.b.(5).G, the Commission required that centralized E&P Waste management facilities be located at least 2,000 feet from the nearest building unit or high occupancy building unit, unless all building unit owners and tenants within 2,000 feet consent to a closer location. Centralized E&P Waste management facilities are designed to process high volumes of E&P Waste, which includes numerous constituents that may impact human health, and accordingly it is reasonable and necessary to separate centralized E&P Waste management facilities from areas intended for human occupation to protect public health.

Several stakeholders suggested that the Commission change some of the existing requirements in Rule 907.b.(5). The Commission determined that its Staff have successfully implemented prior Rule 908's permitting process, and that no changes are necessary. Rule 907.b.(5).B's requirement for scaled drawings of entire sections refers to entire Public Land Survey sections. The 10 foot fire lane width in Rule 907.b.(5).D was included in prior Rule 908.b.(5).D, and the Commission did not change this width because the Commission has found it to be necessary to ensure safety of centralized E&P Waste management facilities.

In Rule 907.b.(6), the Commission clarified that characteristic waste profiles must include analysis of representative waste samples by an accredited laboratory. This clarifies an area of ambiguity under the Commission's prior Rule 908.b.(6). The Commission instructs its Staff to issue guidance about what a waste profile must include.

The Commission re-ordered some of the requirements for centralized E&P Waste management facility design and engineering in Rule 907.b.(7) and made eight substantive changes to the Rule.

First, the Commission required facility design, engineering, and as-constructed plans to be reviewed and stamped by a certified Colorado Professional Engineer ("P.E."). Several stakeholders requested that the Commission not adopt this change. The Commission determined that this change is necessary and reasonable because the judgment of the Commission's Staff, many of whom are certified Colorado P.E.'s, is that all information listed in Rule 907.b.(7) would subject to the expertise of a P.E. However, the Commission recognizes that some of the hydrologic data listed in Rule 907.b.(7).B may be outside the specific expertise of some P.E.'s that may review the other geologic and engineering data in 907.b.(7). In such a case, the Commission intends to allow the P.E. reviewing the plan to exclude that information from their stamp, if necessary.

Second, the Commission clarified what it intended to require by a review of shallow groundwater. The Commission intends to require operators to identify the shallowest unconfined groundwater formation, as well as any underlying groundwater formations. The groundwater at greatest risk of contamination at a centralized E&P Waste management facility is the groundwater closest to the surface, but it is also important for the Commission's Staff to receive complete information about all underlying groundwater formations to facilitate their review of a Form 28. Some stakeholders suggested that the Commission limit its requirement for operators to provide data about the existing quality of the shallowest groundwater formation to situations where such data is available. The Commission did not adopt that suggestion, because obtaining a baseline groundwater sample is necessary to monitor for any future changes in groundwater quality. If no pre-existing water wells are available, the Commission may require the operator to install on site monitoring wells and obtain baseline data prior to site approval. The Commission will issue guidance about the specific limited circumstances where site-specific monitoring may be required as part of the facility design process and prior to permit approval.

Third, consistent with Rule 910.e.(5)'s requirement for all new pits to be constructed and designed with leak detection systems, in Rule 907.b.(7).C.iii, the Commission required operators to describe the design of leak detection systems or other containment systems at centralized E&P waste management facilities.

Fourth, in Rule 907.b.(8).I, the Commission required operators to submit a stormwater management plan as part of the operating plan for centralized E&P Waste management facilities. Some stakeholders questioned whether additional reclamation plans should be included in the centralized E&P Waste management planning process. The Commission determined that although stormwater management information is an important component of active operations, other reclamation concerns are better addressed through the Rule 907.h preliminary closure plan, consistent with current practice.

Fifth, in response to stakeholder requests, the Commission clarified that the operating plan required by Rule 907.b.(8) should incorporate best management practices. Some stakeholders questioned what types of records operators would be required to keep pursuant to Rule 907.b.(8).F's recordkeeping requirement. The Commission did not change this Rule, which was prior Rule 908.b.(8).F. The Commission will continue requiring operators to maintain records of the type and volume of waste handled, transportation information, and the source of waste, as required by Rule 905.b.(3).

Sixth, the Commission substantially revised the groundwater monitoring requirements in Rule 907.b.(9). Consistent with its efforts to consolidate all groundwater monitoring requirements into a single Rule 615, in Rule 907.b.(9).A, the Commission cross-referenced Rule 615, rather than providing distinct but overlapping requirements for centralized E&P Waste management facilities in Rule 907.b.(9). However, the Commission maintained the 1-mile radius requirement of prior Rule 908.b.(9).A. The Commission determined that it is appropriate to maintain the 1-mile radius because groundwater contamination plumes may migrate long distances in shallow alluvial formations. Additionally, the large volume of waste processed by a centralized E&P Waste management facility makes it especially important to obtain baseline data within a reasonable radius. Finally, the 1-mile radius increases the likelihood that there will be existing water wells within the sampling radius to use as valid sampling points, rather than operators being required to drill separate monitoring wells. However, consistent with Rule 615.c, operators may request an exception to the groundwater monitoring requirements in Rule 907.b.(9) if there are no available water sources within the 1-mile radius.

The Commission also substantially revised the requirements for site-specific monitoring wells in Rule 907.b.(9).B. Under Rule 907.b.(9).B, the Director may require operators to install site-specific monitoring wells to ensure that centralized E&P Waste management facilities comply with Table 915-1 standards and WQCC Regulation 41. The Commission recognizes that site-specific monitoring may not be appropriate in all cases, such as circumstances where there is no shallow groundwater beneath the location until a depth of several hundred feet. The Commission intends for the Director to appropriately exercise discretion to require site-specific monitoring wells only where necessary, such as in areas where there is shallow groundwater present. The Commission also formally incorporated the State Engineer's Water Well Construction and Permitting Rules by reference in Rule 901.b, and referenced the rules in Rule 907.b.(9).B.ii. Prior Rule 908.b.(9).B.ii also referenced the State Engineer's Rules, and the Commission only formalized the incorporation by reference to comply with the APA. C.R.S. § 24-4-103(12.5).

Seventh, the Commission clarified that the WQCC standards and classifications cross-referenced in Rule 907.b.(10) include narrative standards, and also clarified language explaining the procedures for operators to follow if they cannot obtain access to surface water sampling locations. Some stakeholders questioned how the Commission would interpret the term "where applicable." The Commission did not revise this language, which was part of prior Rule 908.b.(10), in the 800/900/1200 Mission Change Rulemaking. The Commission determined that this language provides necessary flexibility in identifying suitable surface water monitoring locations, as opposed to a numeric distance threshold. For example, surface water might be relatively close to a proposed centralized E&P Waste management facility, but upgradient, making surface water sampling less necessary due to the low risk of contamination. By contrast, surface water located downgradient but some distance away from a proposed centralized E&P Waste management facility could be at a greater risk of contamination and require monitoring, based on the unique hydrological and topographical properties of an area.

Finally, in Rule 907.b.(11), the Commission specified that contact information for the local emergency response authority must be included in the contingency plan.

Rule 907.c

In Rule 907.c, the Commission substantially revised its standards for approval, denial, and conditional approval of Form 28 permit applications for centralized E&P Waste management facilities. Consistent with Senate Bill 19-181's changes to the Commission's statutory authority and mission, *see* C.R.S. §§ 34-60-102(1)(a)(I) & (b), 34-60-103(5.5), & 34-60-106(2.5)(a), the Director may approve centralized E&P Waste management facilities only if the proposed facility protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

The Commission clarified that the Director may also attach conditions of approval to permits where necessary and reasonable to comply with the Commission's statutory directive, C.R.S. § 34-60-106(2.5)(a), and to ensure compliance with Table 915-1 and the WQCC's groundwater quality standards and classifications. In Rule 907.c.(3), the Commission provided clear criteria governing when the Director may deny a centralized E&P Waste Management facility permit that does not adequately protect or minimize impacts to public health, safety, welfare, the environment, and wildlife resources.

Some stakeholders raised questions about the timeframe for the Director's review and decision to approve or deny a centralized E&P Waste management facility permit. In response, the Commission adopted Rule 907.c.(1), which requires the Director to issue a completeness determination for a centralized E&P waste management facility permit within 90 days of the Form 28 being submitted. The use of a completeness determination is consistent with other Commission Rules for complex permitting processes. *See* Rule 303.b. However, the Commission chose not to limit the overall timeframe for the Director's review. The Act requires a timely and efficient review procedure only for the Commission's review of Form 2 applications for permits to drill and applications for drilling and spacing units. C.R.S. § 34-60-106(11)(a)(I)(A). However, the Commission's Staff will continue to process centralized E&P Waste management facility permit applications in the same timely and efficient manner with which they process Form 2 applications for permits to drill and drilling and spacing unit applications. The Commission chose not to adopt a timeframe to limit the Director's review in part because the Commission recognizes that there is wide variability among centralized E&P Waste management facilities, and that permit review may take a relatively short period of time for smaller, more straightforward facilities, but several months or longer for larger, more complex facilities in more sensitive areas. The Commission recognizes that there is no one-size-fits-all solution for the timeframe for processing centralized E&P Waste management facility applications. The Commission determined that imposing an unduly limiting timeframe might stymie important dialogue between permit applicants and the Commission's Staff, and could also potentially result in the Director denying permit applications that could be approvable if the applicant had more time to work through issues with the Commission's Staff. Finally, the transition to a full-time Commission will allow for a more timely and efficient hearings schedule which will impact all permit reviews.

Rule 907.d

The Commission did not substantively revise Rule 907.d (prior Rule 908.e), governing financial assurance for centralized E&P Waste management facilities. Numerous stakeholders provided feedback about Rule 907.d. The Commission will address those stakeholders' concerns in the forthcoming Financial Assurance Rulemaking required by Senate Bill 19-181. C.R.S. § 34-60-106(13).

Rule 907.e

The Commission revised Rule 907.e (prior Rule 908.e), governing facility modifications, only to clarify that proposed modifications should be submitted on a Form 4.

Rule 907.f

The Commission adopted a new Rule 907.f, governing the expiration of centralized E&P Waste management facility permits where the operator does not timely commence construction. Consistent with Rule 311, the Commission adopted a three year expiration date.

Rule 907.g

The Commission did not substantively revise Rule 907.g (prior Rule 908.f), governing annual review of centralized E&P Waste management facility permits.

Rule 907.h

The Commission did not revise Rule 907.h (prior Rule 908.g), governing closure of E&P Waste management facilities, except to clarify that the purpose of providing a cost estimate pursuant to Rule 907.h.(1).B is to verify that the financial assurance provided pursuant to Rules 907.d and 704 is appropriate. It is necessary for the Commission to have a basis for determining remediation and reclamation costs for closure of a centralized E&P Waste management facility, which is why Rule 907.h.(1).B requires a cost estimate.

Rule 908.

The Commission moved prior Rule 903, governing pit permitting and reporting requirements, to Rule 908, and consolidated it with prior Rule 335, which required all pits to obtain a Form 15, Earthen Pit Permit.

Rule 908.a

In Rule 908.a, the Commission simplified the language of prior Rules 903.a and 335 to list the four categories of new pits that operators may construct if the operator submits and receives approval of a Form 15. Some stakeholders suggested that the Commission not allow any new pits at all, but the Commission did not accept these suggestions. The Commission determined that it is not necessary to completely prohibit pits for the seven reasons discussed below, because it could provide adequate environmental protection by instead strengthening its operational standards for new and in some cases existing pits.

First, the Commission strengthened its standards for pit lining in Rule 910, and standards for pit liner maintenance in Rule 909.b, which will provide better protection for the environment from one of the main categories of environmental impacts caused by pits—leaks into soil and groundwater.

Second, the Commission strengthened its standards for excluding wildlife, livestock, and persons from both new pits through fences, netting, and other exclusion methods approved by CPW in Rules 603.h, 909.f, and 1202.a.(4), which may also apply to existing pits on a case-by-case basis.

Third, the Commission adopted emissions standards for all new pits statewide in Rule 903.d.(6).A, strengthened emissions standards for existing pits in Rule 903.d.(6).A, and limited the open pit storage of hydrocarbon substances in Rule 910.d.

Fourth, the Commission strengthened standards to reduce the risk of overflows by strengthening standards for freeboard monitoring in Rule 909.c, and expanding prior Rule 604.c.(2).K, requiring pit level indicators to apply statewide in Rule 603.f.

Fifth, the Commission banned new skim pits in Rule 910.b, adopted specific requirements for cuttings trenches in Rule 905.g.(2).E, and removed exceptions governing some categories of pits from prior Rule 903 to address certain categories of pits that unique risks that were not addressed by the Commission's prior Rules.

Sixth, to prevent trash accumulation in pits, the Commission strengthened its standards governing trash in Rule 606.d, and for removal of pit liners in Rule 911.c.

Seventh, as shown in the Tables 900-1 and 900-2 below, oil and gas operations in

Colorado have generally shifted away from using pits, and the number of permit applications for new pits has dramatically declined in recent years.

Ultimately, the Commission recognized that there is no perfect solution to fluid storage. Although pits pose a variety of risks to public health, safety, welfare, the environment, and wildlife resources, other methods of fluid storage, such as tanks, also pose their own set of risks to public health, safety, welfare, the environment, and wildlife resources. By adopting a robust set of standards for both pits and tanks, the Commission determined that it has adopted an approach to fluids management that is consistent with its statutory mandates, including Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a).

Table 900-1: Form 15 Earthen Pit Report/Permit by Year *[Includes new pit permit applications, and reports submitted for transfers or modifications of existing pits]*	
2000	328
2001	235
2002	253
2003	353
2004	236
2005	455
2006	296
2007	178
2008	339
2009	123
2010	117
2011	176
2012	69
2013	88
2014	44
2015	12
2016	14
2017	59
2018	16
2019	3
2020	1

Table 900-2: Form 15 Earthen Pit Permits by Year *[Includes only applications for new pit permits]*	
2017	4
2018	6
2019	2

Rule 908.b

Although Rule 908.a only applies to new pits, the Commission adopted a new Rule 908.b to clarify that operators must submit a Form 15 application, and obtain the Director's approval of the application, prior to enlarging or modifying an existing pit.

Rule 908.c

In Rule 908.c, the Commission revised the categories of pits listed in prior Rule 903.b that operators may permissibly construct without prior Commission approval. Under revised Rule 903.c.(1), operators may only construct pits used in the initial phases of emergency response without prior Director approval on a Form 15, including emergency pits, plugging pits, and workover pits. Operators may also construct cuttings trenches that were approved on a Form 2A without prior Director approval on a Form 15. However, for both categories of pits, operators must submit a Form 15 Pit Report to the Director within 30 days of constructing the pit.

Rule 908.d

In Rule 908.d, the Commission revised the standards for review and approval of a Form 15 in prior Rule 903.e. First, the Commission required Form 15s to be submitted concurrently with a Form 2A, rather than a Form 2, consistent with broader changes to the permitting process in the Commission's 300 Series Rules. Second, consistent with this change, the Commission removed the timeframe limiting the Director's review of a Form 15, which was inconsistent with the timeframe provided for processing Form 2A applications in the Commission's 300 Series Rules. Third, consistent with Senate Bill 19-181's changes to the Commission's statutory authority and mission, *see* C.R.S. §§ 34-60-102(1)(a)(I) & (b), 34-60-103(5.5), & 34-60-106(2.5), the Commission provided that the Director may approve Form 15 pit permits only if the proposed pit protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Commission clarified that the Director may also attach conditions of approval to pit permits where necessary and reasonable to comply with the Commission's statutory directive, C.R.S. § 34-60-106(2.5)(a). And the Commission provided clear criteria governing when the Director may deny a pit permit that does not adequately protect or minimize impacts to public health, safety, welfare, the environment, and wildlife resources.

Some stakeholders requested specific surface owner consultation about Form 15 applications. The Commission did not adopt this suggestion, because surface owner consultation is already required for pits at new oil and gas locations pursuant to Rule 309.b.(1).D, because pits are among the types of production facilities and infrastructure that must be specifically identified during the surface owner consultation process.

Rule 909.

The Commission moved prior Rule 902, Pits – General and Special Rules, to Rule 909, and renamed the Rule as Pits – Construction and Operation, to better reflect the Rule's purpose. As with all Rules the Commission adopted in the 800/900/1200 Mission Change Rulemaking, the Commission intends for Rule 909 to be prospective—applying only to new operations after January 15, 2021—unless otherwise specified. Thus, construction standards for building new pits in Rule 909 would only apply to new pits built, and existing pits that are significantly modified after January 15, 2021. However, the Commission does intend for components of Rule 909 that involve ongoing activities or operations that occur at existing pits after January 15, 2021 to apply to existing pits.

Rule 909.a

The Commission adopted a new Rule 909.a, governing permitting and reporting for operational pits. The Commission's Staff have frequently encountered challenges with remediation and reclamation projects because of operators failing to maintain accurate facility records documenting the location and status of pits. Rule 909.a is intended to ensure that the Commission has accurate and up to date information about all operational pits. The Commission determined that Rule 909.a is necessary because some pits that existed prior to 1998 were registered with the Commission pursuant to the version of the Commission's Rules that were applicable at the time, but the required follow up information may not have been submitted. Rule 909.a.(1) ensures that the Commission will have the information it needs to administer its Rules for all pits by requiring proper registration of any such pits constructed prior to 1999 that are still used in active operations. Moreover, many registered pits were ultimately only located by quarter-quarter section, and therefore they are not found in their actual location on the Commission's online map tool (COGIS). Rule 909.a.(2) ensures that pits and former pits can be readily identified by location when using the Commission's COGIS mapping system.

Rule 909.b

In Rule 909.b, the Commission revised prior Rule 902.a, which set standards for pit construction and operations, to make it consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). The Commission also adopted standards requiring appropriate maintenance of pits and pit liners to prevent spills and releases.

Rule 909.c

In Rule 909.c, the Commission clarified that pits must be constructed, monitored, and operated to maintain at least two feet of freeboard at all times, resolving ambiguities in prior Rule 902.a.

Rule 909.d

The Commission moved prior Rule 323 governing open pit storage of oil and hydrocarbon substances to Rule 909.d. Prior Rule 323 was adopted as part of the Commission's first set of Rules in 1952 (initially, the Rule was Rule 334, and titled Open Pit Storage of Oil). Rule 909.d limits open pit storage of oil and hydrocarbon substances to only during emergencies where the substances could not otherwise be controlled, and requires removal of the hydrocarbons as soon as the emergency is controlled, without any option for extension. The Commission also moved prior Rule 903.b.(1), requiring operators to submit a Form 15 to the Director documenting the open pit storage of the hydrocarbons within 30 days of the beginning of the emergency conditions, to Rule 909.d. Some stakeholders questioned whether Rule 910.d includes produced water because of the use of the term "produced liquid hydrocarbon substances." Consistent with its interpretation of the same language in prior Rule 323, the Commission does not intend for Rule 910.d to govern the storage of produced water in pits. The Commission interprets the term "produced liquid hydrocarbon substances" to refer to crude oil, condensate, or any other "free-phase" liquid hydrocarbon.

Rule 909.e

In Rule 909.e, the Commission updated prior Rule 902.c's standards prohibiting the presence of liquid hydrocarbons in a pit. Because the presence of liquid hydrocarbons in a pit poses risks to public health, safety, welfare, the environment, and wildlife resources through air emissions, fire risk, odors, increased potential for harm in the event of a spill or release, and increased risk of wildlife mortality if wildlife enter or drink from pits, the Commission determined that the presence of any liquid hydrocarbons in a pit is not consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). Accordingly, the Commission clarified and strengthened its standards prohibiting the presence of liquid hydrocarbons in pits. The Commission required the immediate removal of liquid hydrocarbons upon discovery, and delegated authority to the Director to revoke an operator's Form 15 pit permit and require the operator to close and remediate the pit in the event of non-compliance. Several stakeholders raised questions about whether skim pits, which by definition may contain liquid hydrocarbons, are regulated by Rule 909.e. As specified in the text of the Rule, the Commission exempted skim pits from Rule 909.e. Stakeholders also questioned why the Commission prohibited the presence of hydrocarbon sheen in pits. The Commission determined that prohibiting the presence of hydrocarbon sheen in pits is an effective mechanism of prohibiting the presence of liquid hydrocarbons in a pit, because the presence of hydrocarbon sheen is a clear indicator of the presence of liquid hydrocarbons that is visible to the naked eye and does not require time intensive testing methods. Prohibiting the presence of hydrocarbon sheen will facilitate easier compliance by operators and easier enforcement by the Commission.

Rule 909.f

In Rule 909.f, consistent with changes to Rules 603.h and 1202.a.(4), the Commission revised prior Rule 902.d, governing fencing and netting pits. The Commission required that all new pits must be fenced, and either netted or covered with another wildlife exclusion method approved by CPW pursuant to Rule 1202.a.(4). The Commission determined that this is necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife. *See* C.R.S. § 34-60-106(2.5)(a). Fencing and netting pits is an effective mechanism of excluding access by humans (members of the general public), and therefore protects public health, safety, and welfare. Fencing and netting pits is also an effective mechanism of excluding access by livestock, and therefore protects public welfare by reducing livestock mortality and morbidity. More importantly, fencing and netting pits is important for preventing wildlife mortality. The experience of both the Commission and CPW, as well as evidence in the administrative record, demonstrates that wildlife mortality, especially bird mortality, is a significant and ongoing risk posed by some pits. Pursuant to Rule 1202.a, operators may seek a waiver from CPW if netting or fencing a new pit is not appropriate on a case-by-case basis, and may also seek a variance from the Commission pursuant to Rule 502 as part of the operators' Form 15 pit permit application.

The Commission recognizes that the risks to wildlife, public health, and the environment posed by pits varies significantly depending on the characteristics of the produced water stored in the pit. Specifically, pits with very low levels of hydrocarbons and salinity (TDS) pose very low risks, and may in some circumstances provide substantial benefits as a source of drinking water for domestic livestock and wildlife. The Commission recognizes that this is especially true for pits in the Raton Basin because of the unique nature of the produced water associated with coalbed methane development in some parts of the Basin. Accordingly, the Commission recognizes that it could be appropriate for an applicant seeking a Form 15 permit for a new pit in the Raton Basin, or in another area with demonstrably high-quality produced water, to seek a variance from the fencing and netting requirement of Rule 909.f, pursuant to Rule 502.

Whether an existing pit is required to be netted or fenced is governed by Rule 1202.a.(4). The Commission recognizes that the produced water sampling and analysis required by Rule 909.j will inform the decision about whether fencing or netting is appropriate for an existing pit, based on the characteristics of the produced water in the pit, and whether those characteristics could be harmful to wildlife that ingests or otherwise comes into contact with the produced water. The Commission intends for its Staff to make appropriate revisions to the Form 43 and other forms used to report data pursuant to Rule 909.j to facilitate Staff's ability to evaluate whether existing pits should be fenced or netted.

Rule 909.g

In Rule 909.g, governing multi-well pits, the Commission revised confusing language in prior Rule 902.e to provide better clarity for operators, and resolve confusion that had arisen under the Commission's prior Rules and prior 100 Series definitions of "Multi-Well Pit" and "Centralized E&P Waste Management Facility." Consistent with changes the Commission made to improve clarity throughout all of its Rules, the Commission removed language specifying that operators may obtain a variance. Operators may still obtain a variance from Rule 909.g by following the procedures for obtaining a variance in Rule 502.

The purpose of Rule 909.g, like prior Rule 902.e, is to avoid the creation of large pit complexes, which should be regulated as centralized E&P Waste management facilities in most cases. Consistent with the Commission's prior practice, the text of Rule 909.g clarifies that any multi-well pit complex in use for more than three years must be permitted as a centralized E&P Waste management facility pursuant to Rule 907, unless certain exceptions are met.

Specifically, consistent with prior Rule 904.a.(5), the Commission recognizes that multi-well pits used to store produced water in Huerfano, Las Animas, Logan, Morgan, Washington, and Yuma Counties pose relatively low risks to groundwater, surface water, wildlife, and livestock, because of the very low hydrocarbon content and salinity of produced water in these counties. Accordingly, the Commission intends for operators to continue operating these multi-well pits for more than three years, without converting them to centralized E&P waste management facilities, which otherwise would require lining the pits (among other requirements). As stated in Rules 909.g.(2) and (3), this exemption only applies to multi-well pits in these counties that were constructed prior to May 1, 2011 (in Huerfano and Las Animas Counties) and May 1, 2013 (in Logan, Morgan, Washington, and Yuma Counties), consistent with prior Rule 904.a.(5), which required multi-well pits in these counties to be lined after that date.

However, the Commission recognizes that produced water may vary in quality within a relatively small geographic area, and that even within oil and gas basins in which there is generally high-quality produced water, there may be outlying areas with higher hydrocarbon content and salinity. Additionally, localized variations in wildlife patterns may warrant additional protections in area where wildlife have been demonstrably harmed by produced water in a multi-well pit. Accordingly, in Rule 909.g.(4), the Commission continued to delegate to its Staff discretion to require an operator to line, fence, net, cover, or close a multi-well pit in Huerfano, Las Animas, Logan, Morgan, Washington, or Yuma Counties if evidence indicates that the continued operation of the multi-well pit may pose a risk to groundwater, livestock, wildlife, surface water, or soil resources. Additionally, the Commission's Staff may require the operator to convert the facility to a centralized E&P Waste Management Facility by submitting a Form 28 permit application. The Commission intends for its Staff to continue to make determinations under Rule 909.g.(4) on a case by case basis based largely on the data submitted pursuant to Rule 909.j, although other sources of information, such as known wildlife deaths or other forms of harm to wildlife or livestock, may also inform this decision.

Consistent with the changes to Rule 909.g, the Commission also revised the 100 Series definitions of Centralized E&P Waste Management Facility and Multi-Well Pit.

First, the Commission revised the definition of Centralized E&P Waste Management Facility to remove cross-references to prior Rules 902.e and 903, and replaced them with a reference to Rules 909.g.(2)–(3). Second, the Commission clarified that the exception to the ordinary rule that a waste facility operated for more than three years must be permitted as a Centralized E&P Waste Management Facility. Under the clarified exception, it is now clear that a Multi-Well Pit in Huerfano, Las Animas, Logan, Morgan, Washington, and Yuma Counties that meets the criteria in Rules 909.g.(2)–(3) need not be permitted as a Centralized E&P Waste Management Facility.

The Commission similarly revised the 100 Series definition of Multi-Well Pit to remove the prior requirement that such pits be permitted as a Centralized E&P Waste Management Facility if in use for more than three years. The timeframe for when (if ever) Multi-Well Pits in various parts of the state must be re-permitted as a Centralized E&P Waste Management Facility is now specified in the text of Rule 909.g.

Rule 909.h

The Commission did not substantively revise Rule 909.h (prior Rule 902.h), governing treatment of produced water that is placed in production pits.

Rule 909.i

The Commission did not substantively revise Rule 909.i (prior Rule 902.i), governing the use of biocide treatments to control bacterial growth and odors.

Rule 909.j

The Commission adopted a new Rule 909.j, governing produced water quality analysis for produced water that is placed into pits. The Commission's prior 900

Series Rules, including Rules 901.a, c, d, and e, provided for limited sampling and analysis of produced water on a case by case basis, but did not provide comprehensive sampling and analysis procedures for produced water. Because Rule 909.j is a change from the Commission's prior Rules, the Commission instructed its Staff to issue guidance for operators about how to implement Rule 909.j. The purpose of Rule 909.j is to ensure that operators sample, and the Commission obtains data about, produced water from all pits in Colorado. Because placing produced water into a pit is an ongoing operation, the Commission intends for Rule 909.j to apply to both new and existing pits.

The Commission determined that it was necessary and reasonable to expand the sampling parameters for produced water because baseline data about the characteristics of produced water is necessary for the Commission's Staff to effectively regulate the reuse, recycling, and disposal of produced water in both pits pursuant to Rule 909.j, and in Class II UIC wells pursuant to Rules 803.g.(5).C & D, 803.h.(1), and 806.c. The full suite of analytical parameters will allow the Commission to better characterize produced water that is disposed in pits, and will provide important data for the Commission and other state agencies to determine whether future regulatory efforts are necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources. Thus, Rule 909.j only applies to produced water placed into a pit—the Commission determined that this will provide an adequate range of information about produced water statewide, without requiring sampling of all produced water.

To provide operators with sufficient time to implement the new sampling protocol, the Commission allowed operators one year from the effective date of the Mission Change Rules to conduct their initial sample, and 1.5 years to submit the initial sampling data to the Commission (unless the pit is closed within 1.5 years, in which case sampling data must be submitted at the time of pit closure). The Commission determined that this will allow operators, laboratories, and the Commission's Staff sufficient time to collect initial samples and process and review the data.

Rule 909.j.(1)

In Rule 909.j.(1), the Commission specified the list of analytes for which produced water samples must be analyzed. Consistent with the Commission's broader efforts to increase consistency in sampling analysis throughout the Commission's Rules, the list of analytes is the same as the list of analytes in Rule 615.e.(2).

The only exception is that the Commission included isotopes of radium in Rule 909.j.(1).K and total suspended solids in Rule 909.j.(1).C. As discussed above, the Commission determined that it is necessary and reasonable to require testing for these radioactive isotopes as part of the Commission's and CDPHE's broader efforts towards better understanding the presence of NORM and TENORM in produced water formations and produced water. The Commission chose isotopes of radium in Rule 909.j.(1).K because they are the isotopes the Board of Health will use to determine if a waste falls under its newly-adopted the TENORM regulations. *See* 6 C.C.R. § 1007-1:20.2 (adopted Nov. 18, 2020). The Commission included total suspended solids because they will be necessary to convert the concentration of radium isotopes from values in milligrams per liter to milligrams per kilogram, which is a necessary component of determining compliance with the Board of Health's TENORM regulations. *See* Board of Health, *Statement of Basis and Purpose and Specific Statutory Authority for Amendments to 6 C.C.R. § 1007-1, Part 20 & 6 C.C.R. 1007-1, Part 12* at pp. 4–5 (Nov. 18, 2020).

Some stakeholders suggested that it is unnecessary to test produced water for NORM because produced water contains little NORM. Because the Commission has not previously required testing of produced water for NORM, the Commission determined that there is insufficient evidence in the administrative record to make a conclusive determination about the prevalence of NORM in produced water at this time. The Commission may revisit its decision to require testing produced water for NORM at a future date, based on the data collected by operators pursuant to Rule 909.j.(1).K. At this time, the Commission required only testing for radiological isotopes in produced water as an effort towards better characterizing produced water and did not adopt a parallel cleanup standard for radioactive isotopes in Table 915-1.

Other stakeholders suggested that the Commission should require testing of produced water for a wider array of radioactive and daughter isotopes and radioactivity indicators, including uranium, thorium, and gross alpha and beta. The Commission determined that it is unnecessary to adopt standards to test produced water for these isotopes and indicators at this time. The Commission required testing for the two isotopes of radium defined as TENORM radionuclides in the Board of Health's recently-adopted TENORM regulations, which will provide a first step towards radiological profiling of produced water samples.

<u>Rule 909.j.(2)</u>

In Rule 909.j.(2), the Commission adopted a schedule for subsequent sampling of produced water in pits. The Commission determined that subsequent sampling is appropriate to provide data trends over time that can inform its Staff about any changes in produced water quality that might warrant changes in control technologies or management approaches. Because data collected under Rule 909.j is crucial to so many of the Commission's other pit regulations—including Rules 903.d.(6), 909.f, 909.g, and 1202.a.(4), obtaining longitudinal data is crucial for ensuring that the Commission's Rules regarding pits are implemented in a manner that protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

Under Rules 909.j.(2).A & B, operators must only conduct one subsequent confirmation sample for lined pits, but must conduct ongoing sampling for the life of an unlined pit, unless the subsequent sampling indicates that there is no change in produced water quality over time. This difference in sampling frequency reflects that lined pits pose less risks to groundwater, surface water, and wildlife than unlined pits due to other Commission Rules intended to minimize adverse impacts from unlined pits. The Commission intends to delegate its Staff discretion to determine whether produced water quality in an unlined pit is "stable" over time, recognizing that some changes in analytes are to be expected over time, and that it is inappropriate to specify exact, quantitative parameters for changes in each analyte in regulatory text given the differences between analytes and in the characteristics of produced water across basins.

Under Rules 909.j.(2).C & D, operators must conduct subsequent sampling any time the source of produced water sent to a pit changes, either because of known changes in that water quality or because a new well is sending water to the pit.

In Rule 909.j.(2).E, the Commission authorized its Staff to require more frequent or additional sampling on a case-by-case basis. Circumstances may arise that warrant additional sampling, such as unexpected wildlife or livestock mortality, a spill or release, or the discovery of elevated contaminant levels in nearby soil, groundwater, or surface water. Additionally, variation between initial and periodic subsequent sampling required by Rule 909.j.(2) may warrant additional sampling. Rule 909.j.(2).E allows the Commission's Staff discretion to respond to these potential threats to public health, safety, welfare, the environment, or wildlife resources as appropriate.

Rule 909.j.(3)–(4)

In Rules 909.j.(3)–(4), the Commission adopted clear sampling and reporting protocols for produced water samples collected pursuant to Rule 909.j. The Commission intends for operators to adhere to the same sampling and reporting protocols for both initial and subsequent samples. All samples must be submitted within 3 months of when they are collected, consistent with Rule 615.f. The Commission also intends for operators to share the results of analysis pursuant to Rule 909.j with the surface owner of the land surface where the pit is located upon request.

When reviewing data submitted pursuant to Rule 909.j, the Commission intends for its Staff to consider whether an existing pit is already lined, fenced, or netted, and whether fencing and netting may be appropriate pursuant to Rule 1202.a.(4). The Commission therefore directs its Staff to revise the Form 43 as appropriate to accommodate relevant data about the status of liners, fencing, and netting at a pit.

Rule 909.j.(6)

In Rule 909.j.(6), the Commission clarified that it does not intend for operators to be required to sample all produced water that is produced from the same formation in the same field or unit and transferred to the same pit (including pits at centralized E&P Waste management facilities). The Commission recognizes that, particularly on the Western Slope, centralized E&P Waste management facilities treat produced water from a large number of oil and gas wells in centralized pits. In other areas, operators commonly use multi-well pits. Because the produced water received by such pits will typically come from oil and gas wells that produce from the same formation or formations with increased well density, the Commission anticipates that there will be a high degree of uniformity in the characteristics of the produced water. Additionally, the prevalence of recycling and reuse of water on the Western Slope creates a homogenization of produced water when managed in centralized E&P Waste management facilities.

For such pits, operators may submit a Form 4 to request the Director's approval of an alternative sampling program to consolidate the number of samples required from the same formation in the same field or unit. This accomplishes the same goals as requiring pit-by-pit sampling pursuant to the ordinary requirements of Rule 909.j, while accommodating the unique waste management configurations used by some operators on the Western Slope and elsewhere. First, Rule 909.j.(6) provides the Commission with representative produced water quality data from produced water formations. Second, Rule 909.j.(6) ensures that operators and the Commission have accurate data about the quality and characteristics of produced water in all pits.

Rule 910.

The Commission moved prior Rule 904, governing pit lining requirements and specifications, to Rule 910.

Rule 910.a

In Rule 910.a, the Commission substantially revised prior Rule 904.a, which required that only certain categories of pits be lined, to instead require lining for all new pits constructed after the effective date of the 800/900/1200 Mission Change Rulemaking, except for cuttings trenches and pits constructed as an initial emergency response measure. The Commission determined that unlined pits present an unjustifiable risk of environmental harm to soil, surface water, and groundwater that is inconsistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. C.R.S. § 34-60-106(2.5)(a).

The Commission exempted cuttings trenches from the lining requirement because, pursuant to the newly-adopted 100 Series definition of "Cuttings Trenches" and Rule

905.g.(2).E, cuttings trenches may contain only cuttings generated from water-based bentonitic drilling fluids. Cuttings trenches are intended to be used for final disposition of E&P Waste, whereas pit liners are considered to be solid waste and cannot be left in place without complying with applicable local government and CDPHE solid waste requirements.

The Commission also exempted pits constructed in the initial phases of emergency response pursuant to Rule 908.c.(1), because in emergency situations the safety and environmental risks of the time required to obtain and install a pit liner would outweigh the environmental harm of temporarily storing fluids in an unlined pit.

Some stakeholders questioned whether percolation pits would be allowed pursuant to Rule 901.a. The Commission does not intend to permit operators to construct any new percolation pits in the future. The Commission determined that percolation pits are not an appropriate disposal method for E&P Waste because they inherently involve the release of contaminants into the environment in a manner that is not consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. C.R.S. § 34-60-106(2.5)(a). The Commission determined that changes were necessary because its prior Rules, adopted in 2008, required a demonstration that the produced water would not impact underlying groundwater resources. However, this was cost-prohibitive for operators to make an adequate determination without employing site-specific hydrologic and contaminant loading evaluation and fate and transport modeling.

Rule 910.b

In Rule 910.b, the Commission revised the standards for skim pits from prior Rule 904.a.(4). As defined in the Commission's 100 Series Rules, skim pits are used to provide retention time for the settling of solids and separation of residual oil for the purpose of recovering the oil or fluid. Skim pits therefore inherently contain oil and other hydrocarbon substances, which is inconsistent with the regulatory changes the Commission adopted in Rules 909.d and e. The Commission therefore determined that skim pits, and specifically unlined skim pits, pose inherent and substantial risks to air, water, and soil that are not consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. C.R.S. § 34-60-106(2.5)(a). The Commission accordingly prohibited the construction of any new skim pits. Additionally, the Commission required all existing skim pits to be retrofitted with a liner. Retrofitting existing skim pits with a liner is necessary and reasonable to protect the environment from contamination by hydrocarbon substances that may leak into soil, surface water, or groundwater from beneath an unlined skim pit. The Commission provided clear standards for implementing the retrofit requirement in Rule 910.b by requiring operators to submit a Form 27 documenting the operator's plan for retrofitting skim pits within approximately three months of the effective date of the 800/900/1200 Mission Change Rulemaking. The Commission does not intend to require operators to install liners beneath all skim pits by April 1, 2021, but rather to submit a Form 27 for the Director's review and approval proposing a timeline for the liner installation by that date.

Rule 910.c

In Rule 910.c, the Commission made relatively minor changes to prior Rule 904.b, which provides specifications for lined pit construction. In Rule 910.c.(2), the Commission required operators to maintain records demonstrating that they followed the manufacturers' specifications for pit lining systems, and to provide those records to the Director upon request. And in Rule 910.c.(3), the Commission added repair documentation to the list of records that operators must maintain and provide to the Director upon request.

Rule 910.d

In Rule 910.d, the Commission made relatively minor changes to prior Rule 904.c, which provides specifications for pit liners in pits that are not located at centralized E&P Waste management facilities. The Commission also required that liner foundations be constructed using material that does not contain sharp rocks or other materials that could puncture the pit liner. Consistent with changes throughout the Commission's Rules, rather than specifying that operators may seek a variance in the text of Rule 910, the Commission intends for operators to seek variances pursuant to Rule 502.

Rule 910.e

In Rule 910.e, the Commission revised prior Rule 904.d, which provides specifications for pit liners for pits at centralized E&P Waste management facilities. In Rule 910.e.(1), the Commission clarified that synthetic or fabric liners may be secured according to manufacturer's specifications if those specifications are different than the Commission's 12 inch anchor trench standard. As in Rule 910.d.(2), in Rule 910.e.(2), the Commission required that liner foundations be constructed using material that does not contain sharp rocks or other materials that could puncture the pit liner. In Rule 910.e.(4), the Commission authorized operators to use double synthetic liner systems as an alternative to soil foundations. Finally, in Rule 910.e.(5), the Commission required all pits at a centralized E&P Waste management facility to be constructed and operated with a leak detection system. Because of the high volume of waste processed at such facilities, and the more intensive and longer duration use of the pits located at those facilities, the Commission determined that additional precautions and more conservative requirements to identify pit leaks are necessary and reasonable to protect soils, surface water, and groundwater from potential contamination.

Rule 910.f

In Rule 910.f, the Commission made relatively minor changes to prior Rule 904.e, to clarify confusing wording. The substantive change the Commission made was to expand the Rule from applying only in sensitive areas to instead apply statewide. As discussed above, the Commission's prior Rule 911 governed pits constructed prior to 1995 that were subject to specific standards if located in sensitive areas. Because the Commission consolidated all of its pit standards into a single set of statewide applicable regulations in Rules 909 and 910, providing separate standards for pits in sensitive areas is no longer necessary.

Rule 911.

The Commission moved prior Rule 905, which governed closure of pits, to Rule 911, and expanded the Rule to provide standards for closure of all oil and gas facilities. The Commission determined that adopting a single regulation specifying closure standards for all facilities would provide clearer guidance to operators about how to remediate and close oil and gas locations at the end of use.

Rule 911.a

In Rule 911.a.(1), the Commission required operators to submit and obtain the Director's prior approval of a Form 27 for closure of all oil and gas facilities. Rule 911.a.(2) provides substantive standards for the information that must be included on a Form 27. The Commission moved prior Rule 905.a.(3), governing closure of emergency pits, to Rule 911.a.(3), but did not substantively revise the Rule. In Rule 911.a.(4), the Commission specified a timeline for submitting a Form 27 for closure of all other oil and gas facilities. The purpose of Rule 911.a.(4) is to prevent undocumented residual impacts from being left at a site after closure and potentially after bond release. This was identified as an issue for the Commission to address in the Commission's 2014 Final Report on Risk Based Inspections: Strategies to Address Environmental Risk Associated with Oil and Gas Operations.[7] Facility closure is often the time when historic spills are discovered, and it is therefore important for operators to submit Form 27s documenting their investigation and remediation plans prior to commencing that work. The Commission determined that it is necessary to adopt such a requirement so that there is certainty that operators have checked for possible contamination beneath tanks, from flowlines, and from other sources where prior leaks and spills are frequently identified during facility closure. Some stakeholders questioned whether a Form 27 must be submitted for decommissioning some equipment at a location that is otherwise active. The Commission does not intend to require a Form 27 for partial decommissioning of an otherwise active oil

[7] https://cogcc.state.co.us/documents/library/Technical/Risk_Based_Inspections/DNR%20-%20OGCC%20Risk%20Based%20Inspection%20Strategy%20FINAL.pdf

and gas location. For example, an operator need not submit a Form 27 to remove one tank from a battery, but would be required to submit a Form 27 during final plugging and abandoning of all wells and removal of all production facilities at a location. In some cases, such as significant modifications to an oil and gas location that also require the submission of a Form 2A or instances when one operator is removing all their equipment from a shared location, the Commission determined that a Form 27 would also be appropriate. The Commission therefore instructed its Staff to prepare guidance for the implementation of Rule 911.a.

Rule 911.b

In Rule 911.b, the Commission expanded the requirements of prior Rule 905.c for discovery of spill or releases during pit closure to cover closure of all oil and gas facilities. Reporting thresholds for such spills or releases are governed by the thresholds established in Rule 912.

Rule 911.c

The Commission moved prior Rule 905.b, which provides specific standards for closure of pits, to Rule 911.c. The Commission made only minor non-substantive changes to the Rule, except for clarifying in Rule 911.c.(2) that operators must collect a sufficient number of representative samples from locations beneath a pit, including sidewall samples, to demonstrate compliance with Table 915-1. Rule 911.c also clarifies that all pit liners must be removed from oil and gas locations upon pit closure, because synthetic pit liners are classified as solid waste by the HMWMD.

Rule 912.

The Commission moved prior Rule 906, governing spills and releases, to Rule 912.

As discussed below, numerous entities, including the Commission, local governments, the surface owner, CDPHE, and CPW receive notices of spills and releases pursuant to Rules 912.b.(7)–(10). Additionally, the Commission makes timely information about spills and releases available on the daily activity dashboard on its website, subject to ongoing updates. However, the Commission also recognizes the importance of providing information to the general public, particularly about spills and releases (and other activities) that occur in the area where a person lives, works, or recreates. The Commission therefore instructs its Staff to work to expand transparency and to explore options for automatic notification of spills and releases to persons who opt-in to receive such notice.

Rule 912.a

In Rule 912.a, to improve clarity, the Commission broke prior Rule 906.a into multiple subsections. The Commission made minor changes to clarify the wording of Rule 912.a.(1), including revising the language to be consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). The Commission also provided that Rule 912.a applies to unauthorized releases of natural gas that meet the criteria of Rules 912.b.(1).H, I, and J. The Commission does not intend for Rule 912.a to prohibit all releases of natural gas, which are addressed through Rule 903 and the AQCC's regulations.

Several stakeholders raised questions about the meaning of the term "immediately" in Rule 912.a.(1). The Commission did not change this term in the 800/900/1200 Mission Change Rulemaking. Consistent with its implementation of prior Rule 906.a.(1), the Commission intends for operators to control or contain spills and releases immediately—meaning as soon as they are discovered.

Stakeholders also raised questions about whether Rule 912.a.(1) covers spills and releases of hydraulic fracturing fluids. If such spills and releases occur before the fluids go downhole, then the spills would be reportable to CDPHE. If the spill or release happens after the fluids return from the subsurface, then the fluids would be classified as E&P Waste and any spills or releases would be reportable pursuant to Rule 912.a.(1).

In Rule 912.a.(2), consistent with Rule 912.a.(1) and Senate Bill 19-181's changes to the definition of "minimize adverse impacts," C.R.S. § 34-60-103(5.5), the Commission changed the term "as soon as practicable" to "as soon as the impacts are discovered."

In Rule 912.a.(3), the Commission made relatively minor revisions to the wording of prior Rule 906.a to conform with Senate Bill 19-181's changes to the Commission's mission and statutory authority. C.R.S. § 34-60-106(2.5)(a). Several stakeholders suggested that Rule 912.a.(3) affords the Director too much discretion to require operators to prevent and mitigate adverse impacts caused by a spill or release. However, the Commission determined that, like prior Rule 906.a, Rule 912.a.(3) provides adequate guardrails for the Director in exercising the Commission's delegated authority. Rule 912.a.(3) only allows the Director to require operators to take actions she determines to be "necessary and reasonable," which are the same statutory standards that constrain the Commission's discretion. *See* C.R.S. § 34-60-103(5.5). The Commission determined that it is appropriate for the Director to have relatively broad discretion to require operators to respond to spills and releases because when a spill or release has occurred, risks to public health, safety, welfare, the environment, and wildlife resources have already been realized. Unlike prophylactic measures designed to avoid and prevent adverse impacts, responses to spills and releases must emphasize minimizing and mitigating the extent of an adverse impact, which may require rapid decisionmaking to respond to changing circumstances. It is thus common for regulatory agencies to adopt fairly strict protections and recognize broad enforcement discretion in the context of spills and releases to allow agencies to react swiftly to potential contamination that may be spreading quickly. Indeed, the General Assembly recognized the unique risks and circumstances posed by spills and releases during oil and gas operations by adopting statutory standards to require reporting of spills of oil and E&P Waste within 24 hours of discovery to both the Commission and local emergency response agencies. C.R.S. § 34-60-130(1).

In Rule 912.a.(4), the Commission made minor changes to the wording of prior Rule 906.a to clarify that operators must document and maintain records demonstrating compliance with Table 915-1 and WQCC Regulation 41 in the event of a spill and release. Some stakeholders questioned whether Rule 912.a.(4) is a standalone requirement that applies outside the context of spills and releases. The Commission does not intend Rule 912.a.(4) to be a standalone requirement, as indicated by it being a subsection of Rule 912.a, which provides general standards for spills and releases. The Commission merely broke prior Rule 906.a into subsections to improve clarity.

Finally, in Rule 912.a.(5), the Commission adopted a new requirement that operators maintain records of cleanup efforts for spills and releases that do not meet the reporting thresholds of Rule 912.b, and provide such records to the Director upon request.

Rule 912.b

The Commission added subsection numbering to several subsections of prior Rule 906.b that were not assigned subsection numbers. Throughout Rule 912.b, the Commission removed the confusing term "Initial Report," and substituted it with "24 Hour Notification," which also aligns with the requirements of the Act. C.R.S. § 34-60-130(1). The Commission clarified that the 24 Hour Notification may be made verbally, in writing (via email), or on a Form 19, Spill/Release Report consistent with the current practices for providing that notification. The Commission intends for operators to continue to make reports directly to its Environmental Staff responsible for regulatory oversight where the spill or release occurred. The Commission also clarified when reports must be made on the Form 19, and distinguished between the Initial and Supplemental versions of the Form 19. These changes do not substantively change the process for reporting, but instead more closely align the regulatory text with the effective spill reporting which currently takes place under the statutory requirements.

The Commission recognizes that an operator who reports a spill or release is not necessarily the party that is responsible for the spill or release. Rule 912.b.(1) requires reporting, and the Commission does not intend for an assumption of responsibility to act as a deterrent to reporting. A lack of clarity about responsibility is not intended to obviate an operator's obligation to immediately control and contain spills or releases upon discovery pursuant to Rule 912.a.(1). However, the

Commission also does not intend for outstanding questions about what party is a responsible party to deter in any way an operator reporting a spill or release, because of the importance of reporting and immediate actions to control and contain spills to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

Rule 912.b.(1)

In Rule 912.b.(1), the Commission revised and added several criteria for which spills and releases must be reported. The Commission added public water systems and wildlife to the list of impacted or potentially impacted resources in Rule 912.b.(1).A. Some stakeholders raised concerns about the implementation of language in Rule 912.b.(1).A requiring reporting of spills or releases that "threaten[] to impact" certain resources. The Commission did not revise this language in the 800/900/1200 Mission Change Rulemaking. The Commission will continue to interpret and implement this language consistent with its prior practice under prior Rule 906.b.(1).A.

The Commission also did not substantively revise Rule 912.b.(1).C. The Commission clarified that the liquids at issue in Rule 912.b.(1).C are E&P Waste and produced fluids, not fresh water. Some stakeholders raised concerns that the 5 barrel threshold for a spill of any material in Rule 912.b.(1) was too low. Based on its experience with implementing prior Rule 906.b.(1).C, the Commission determined that it was necessary and reasonable to maintain this threshold, and did not revise the Rule in response to stakeholder concerns.

In Rule 912.b.(1).D, the Commission required that Grade 1 Gas Leaks must be reported within 6 hours of discovery.

The Commission adopted a new Rule 912.b.(1).E, requiring reporting of the discovery of ten cubic yards or more of impacted material resulting from a potential spill or release. Some stakeholders suggested that the ten cubic yard threshold was too high, and other stakeholders suggested it was too low. Based on the Commission's experience with its orphan well program, which often involves discovery of previously undocumented contamination from historic releases, the Commission determined that ten cubic yards is a reasonable threshold.

Furthermore, the Commission calculated that 10 cubic yards is a reasonably reportable volume based on the following formula which addresses the retention of oil in soil:

$$Volume\ of\ Oil\ (bbls) = \frac{(Volume\ of\ Soil\ (cubic\ yards) \times retention\ factor(\%) \times porosity(\%))}{conversion\ factor\ \left(\frac{cubic\ yards}{bbl}\right)}$$

Because one barrel of oil spilled outside secondary containment is the reporting threshold for known spill volumes, the Commission calculated that 10 cubic yards could easily retain a reportable volume of oil following a spill or release. Table 900-3 compares a finer-grained soil type (silt) with a coarser-grained soil type (sand) and shows the amount of silt and sand that would be impacted by a one barrel spill or release. By using high published retention factors and low porosities, the calculated volumes of soil are conservatively low.

TABLE 900-3		
	Oil in Silt	**Oil in Sand**
Volume of spill (bbl)	1	1
High Retention Factor*	0.2	0.13
Low Porosity**	0.35	0.25
Conversion Factor: cubic yds/bbl	0.21	0.21
Volume of soil (cu yard)	3.0	6.5

*after Alaska Clean Seas Technical Manual, 1999, TACTIC T-7 Spill Volume Estimation
**from Freeze and Cherry, 1979

Further, back-calculating how much oil 10 cubic yards of oil could retain using the same formula, retention factors, and porosities, the COGCC determined that 10 cubic yards of impacted soil could clearly retain a reportable quantity of oil. In silt, 10 cubic yards could retain 3.3 barrels of oil and in sand, 10 cubic yards could retain 1.5 barrels of oil.

Instead of adopting a reporting threshold lower than 10 cubic yards, the Commission believed it was reasonable to set the reporting limit at 10 cubic yards, which is often the volume of one truck load of waste removed from location. Excavation resulting in the removal of 10 cubic yards or more of impacted material reasonably represents a spill volume greater than one barrel in most cases and also allows for some over-excavation of materials to ensure that all impacted soil is removed.

In Rule 912.b.(1).E, the Commission also clarified that reporting discovered spills is not contingent on confirmation sampling to determine whether the material exceeds the standards in Table 915-1. The Commission recognizes that not all spills will result in soil contamination that exceeds the standards in Table 915-1, but the purpose of Rule 912.b.(1).E is reporting, not remediation. Rule 912.b and all of its subsections, including Rule 912.b.(1).E, is intended to ensure that the Commission receives timely notice of spills so that the Commission's Staff may proceed with oversight, investigation, and remediation responses, as appropriate. In the Commission's experience, operators have frequently discovered oil saturated soil at historic release locations and delayed reporting until after testing the material to determine whether it exceeds the standards in prior Table 910-1. This has often resulted in notification to the Commission after excavations are closed preventing direct observations of remediation projects. Additionally, those practices have sometimes resulted in operators conducting remedial excavations and collecting confirmation samples from clean material left *in situ*, which does not properly demonstrate that no spill or release occurred. To prevent such a delay in reporting, the Commission determined it was necessary to clarify that reporting of spills pursuant to Rule 912.b.(1).E is not contingent on testing or analytical results to demonstrate exceedances of the cleanup standards in Table 915-1.

In parallel to Rule 912.b.(1).E, the Commission also adopted a new Rule 912.b.(1).F, requiring reporting of impacted waters of the state, including groundwater, which is similarly not contingent on testing to determine whether the cleanup concentrations in Table 915-1 have been exceeded. Some stakeholders raised questions about how the Commission will work with the WQCC when a spill or release occurs that impacts surface water. Consistent with its current practice and the memorandum of agreement between the Commission and the WQCC, the Commission's Staff will consult with CDPHE to determine which agency is the appropriate lead agency to oversee the investigation and remediation process, and the agencies will also coordinate enforcement actions, if necessary.

In Rule 912.b.(1).G, the Commission adopted a new requirement that operators report suspected or actual spills and releases whose volumes cannot immediately be determined. Because prior Rules 906.b.(1).B and C contained volume thresholds for reporting, in the Commission's experience operators would sometimes unnecessarily delay reporting in circumstances where the volume of the spill was unclear. Rule 912.b.(1).G clarifies that an operator's inability to immediately determine the volume of a spill or release does not excuse the operator from reporting the spill or release. Some stakeholders suggested that Rule 912.b.(1).G rendered other spill and release criteria meaningless. The Commission disagrees with these stakeholders. If a spill or release is clearly and demonstrably of a lower volume than a volume specified in Rules 912.b.(1).B or C, then the spill is not reportable. However, if a spill or release may have a volume greater than the reporting thresholds in Rules 912.b.(1).B or C, but the exact volume has not yet been determined, Rule 912.b.(1).G clarifies that the spill is reportable. In Rule 912.b.(1).G, the Commission also required the reporting of spills and releases of any volume that daylight from the subsurface. The Commission determined that it was important to establish a presumption that if there is a sufficient volume of liquid to reach the surface from a subsurface source, it is important for the Commission to receive notice of the spill, because it is likely that there is a greater volume of liquid beneath the source. Some stakeholders suggested that the term "daylights" is not clear. However, the Commission determined that the term "daylights" is an implementable term, because it refers to any spills that appear at the surface from the subsurface. This is an issue that the Commission has frequently encountered in regulating prior spills and releases, and in the Commission's experience, a spill or release reaching the surface from the subsurface is typically an indication that there is a more significant spill or release often requiring significant soil, and potentially groundwater, remediation efforts.

In Rule 912.b.(1).H, the Commission adopted a new requirement that operators report spills or releases of vaporized hydrocarbon mists that leave an oil and gas location or off-location flowline. The Commission determined that it was necessary to adopt Rule 912.b.(1).H, because the volume of vaporized mists are very difficult to calculate, and even a relatively low volume of a vaporized hydrocarbon may spread across and impact a relatively large area. The Commission further determined that it was necessary to adopt Rule 912.b.(1).H, because its Staff have received numerous complaints about vaporized mists leaving an oil and gas location and impacting other surface owners' property, in situations where an operator did not report a spill or release. Vaporized mists of hydrocarbons have directly impacted roads, canals and irrigation structures, crop land, homes, farm equipment, and other off site personal property, yet have remained below the standard volume reporting thresholds.

In Rule 912.b.(1).I, the Commission adopted a new requirement that operators report releases of natural gas that result in an accumulation of soil gas or gas seeps. And in Rule 912.b.(1).J, the Commission adopted a new requirement that operators report releases of that result in the presence of natural gas in groundwater. The Commission determined that it was necessary to adopt these standards because its other Rule 912.b.(1) standards do not cover subsurface gas releases. Subsurface natural gas releases pose risks of environmental contamination, and also pose significant safety risks if the natural gas reaches the surface or accumulates in water wells, basements, or structures.

Some stakeholders suggested that the Commission limit Rules 912.b.(1).I and J to releases of thermogenic, as opposed to biogenic gas. The Commission did not adopt this suggestion because the Commission does not intend for operators to delay reporting subsurface natural gas releases until testing can be conducted to identify whether natural gas is thermogenic or biogenic in origin.

<u>Rule 912.b.(2)</u>

In Rule 912.b.(2), the Commission revised portions of prior Rule 906.b to provide more specific criteria for how operators must report the location, type, and volume of a spill or release. This implements the Act's requirement that the type of waste involved be part of a spill report, along with any other available information. C.R.S. § 34-60-130(2). The Commission also added two new criteria: that the operator certify that it provided the additional party notifications required by Rule 912.b.(7)–(10), and that the operator describe any threats to waters, occupied buildings, wildlife, air quality, or roads. These additional criteria will facilitate the Commission's Staff swiftly taking appropriate response measures based on the nature of a spill or release. Recognizing that an operator may not have access to advanced global positioning system ("GPS") technology when a spill or release is first identified, Rule 912.b.(2).A allows basic location reporting that includes only latitude and longitude, which may be collected by a handheld GPS unit or similar device, so long as the operator subsequently provides more detailed location data pursuant to Rule 912.b.(4).D.

Rule 912.b.(3)

In Rule 912.b.(3), the Commission assigned subsection numbering to the portion of prior Rule 906.b governing submission of a Form 19 – Initial within 72 hours but did not substantively revise the Rule.

Rule 912.b.(4)

In Rule 912.b.(4), the Commission clarified and provided additional criteria for Form 19 – Supplemental reports filed within 10 days of a spill. The Commission modified the option of providing an aerial photograph of the spill or release to instead require photo documentation of the source of a spill or release, the impacted area, and any initial cleanup activity. The Commission determined that requiring photographic documentation is necessary because written descriptions may not provide the Commission's Staff with sufficient information to determine an appropriate enforcement response. Photographic documentation may also allow the Commission's Staff to choose not to visit and inspect a reported spill or release when evaluating severity relative to other priorities.

Rule 912.b.(5)

In Rule 912.b.(5), the Commission assigned subsection numbering to the portion of prior Rule 906.b authorizing the Director to require additional supplemental reports, but did not substantively revise the Rule.

Rule 912.b.(6)

The Commission adopted a new Rule 912.b.(6), providing procedures for closure or follow up remediation from a spill or release. Rule 912.b.(6) requires operators to submit, within 90 days of a spill or release, either a Form 19 – Supplemental to close the spill because it has been fully cleaned up in compliance with Table 915-1, or a Form 27 because additional investigation, cleanup, or remediation is still necessary. The Commission determined that a 90 day time frame is a reasonable time period to differentiate between relatively minor spills that can be effectively cleaned up within a short period of time, and more significant remediation efforts for which a Form 27 should be required to detail and document the investigation and remediation process.

Some stakeholders suggested that the 90 day time period is too short because spill cleanup may be complex during winter months in some areas of the state. While the Commission recognizes these difficulties, it determined that it would be appropriate for an operator to submit a Rule 502 variance request in such a circumstance, rather than extending the timeframe for closure of all spills and releases statewide. Additionally, many winter spills impact snow and frozen soil and sometimes frozen surface water and become more complex and time-intensive cleanup projects, thus requiring a Form 27 independent of this new requirement.

Rule 912.b.(7)

The Commission moved prior Rule 906.b.(2) to Rule 912.b.(7), but did not substantively revise the Rule. Rule 912.b.(7) implements the Act's statutory provisions governing notification to local emergency response authorities. C.R.S. § 34-60-130(1)(b).

Rule 912.b.(8)

The Commission moved prior Rule 906.b.(3) to Rule 912.b.(8). The Commission revised the Rule to allow either written or verbal notification to the affected surface owner. To make Rule 912.b.(8) enforceable, the Commission adopted a new Rule 912.b.(8).C, requirement operators to document the surface owner notifications. Rule 912.b.(8) requires spill and release reporting to any surface owner, including state and federal agencies such as CPW for spills or releases in state parks, and the State Land Board where the State Land Board is the surface owner. Some stakeholders raised concerns with the confidentiality of the surface owner's contact information. Rule 912.b.(8).C does not require reporting any information about the surface owner to the Commission. However, should the Commission or Director request the operator's records documenting that surface owner notification occurred, any confidential personal information would be subject to the confidentiality provisions of Rule 223.

Rule 912.b.(9)

The Commission moved prior Rule 906.b.(4) to Rule 912.b.(9). The Commission broadened the Rule to require reports to CDPHE's Environmental Release/Incident Report Hotline for any spill that impacts or threatens to impact any surface waters, rather than only surface water supply areas. Consistent with Rules 411.a.(4) and 411.b.(5), the Commission also described the procedures for reporting spills or releases that impact or threaten to impact public water system intakes. The Commission only requires calling the incident report hotline for spills that impact or threaten to impact surface waters, rather than groundwater, because Senate Bill 89-181 makes the Commission an implementing agency for groundwater protection standards. C.R.S. § 25-8-202(7)(a). Accordingly, the Commission's Staff directly addresses spills and releases that impact groundwater, and therefore it is unnecessary to call a CDPHE hotline to notify CDPHE about the impacts to groundwater.

Rule 912.b.(10)

The Commission adopted a new Rule 912.b.(10), requiring spill and release reporting to CPW for spills and releases that occur within high priority habitat, or within 300 feet of surface waters of the state. This will include notification to CPW for spills and releases that occur within state parks and state wildlife areas. The Commission's website will designate contact information for the CPW energy liaison who should receive the notice. This notification ensures that CPW can assess the significance of impacts to wildlife resources from the spill and can make recommendations to the Commission about additional mitigation or enforcement. The Commission recognizes that CPW may not require the same immediacy of notification as other entities and therefore timed this notification with the Form 19 – Initial, rather than with the 24 Hour Notification. However, this Rule 912.b.(10) does not prevent operators from making the notice concurrent with the 24 Hour Notification.

Rule 912.b.(11)

The Commission moved prior Rule 906.b.(5) to Rule 912.b.(11) but did not substantively revise the Rule. The purpose of Rule 912.b.(11) is to remind operators that they may have independent spill reporting obligations pursuant to other state and federal laws, in addition to the spill and release reporting required by the Commission's Rule 912. Some stakeholders suggested that Rule 912.b.(11) exceeded the Commission's statutory authority because it referenced federal statutes. The Commission disagrees with these stakeholders, because Rule 912.b.(11) does not authorize the Commission to enforce any specific provisions of federal laws that are outside the Commission's statutory authority, but rather serves as a reminder to operators that they may be subject to other reporting requirements.

Rule 912.c

The Commission moved prior Rule 906.c to Rule 912.c. The Commission did not substantively revise Rule 912.c.(1), which authorizes the Director to require operators to submit a Form 27 where necessary to remediate the impacts of a spill or release. The Commission revised Rule 912.c.(2), governing surface owner notification of remediation activities, to provide additional clarity around the operator's obligation to obtain access to remediation sites from a surface owner. Prior Rule 906.c.(2) provided that an operator's efforts to negotiate access to a site for remediation could not unreasonably delay commencement of remediation operations. Rule 912.c.(2) clarifies that an operator's failure to obtain access to a remediation site does not relieve the operator of its responsibility to commence or complete required remediation operations. An operator that is responsible for a spill or release that impacts a surface owner's property will have already trespassed onto the surface owner's property through the spill or release itself, and it is therefore the operator's responsibility to timely obtain the right to access the surface to remedy the trespass caused by the spill or release.

Rule 912.d

The Commission moved the standards for spill and release prevention from prior Rule 906.d.(2) to Rule 912.d.(1). The Commission moved the standards for secondary containment from prior Rule 906.d.(1) to Rule 603.o. The Commission added Grade 1 Gas Leaks to the categories of spills and releases subject to Rule 912.d. The Commission also required operators to document measures they implement to prevent future spills or releases due to similar causes.

The Commission adopted a new Rule 912.d.(2) to clarify that the Director may initiate enforcement action if a spill or release occurs at a site subject to the control of the same operator as a result of the similar causes identified in Rule 912.d.(1). This clarifies the Director's pre-existing authority to take enforcement action if an operator fails to comply with Rule 912.d.(1) by implementing measures to prevent future spills or releases from the same or similar causes.

In Rule 912.d.(3), the Commission required operators to provide to the Director upon request documentation of any evaluations or other steps taken to prevent spills or releases due to similar causes.

Rule 912.e

Consistent with changes to Rule 912.b.(1).G requiring operators to report suspected spills or releases, the Commission adopted a new Rule 912.e providing procedures for operators to close a suspected spill or release that ultimately proved not to exceed any applicable reporting thresholds. Pursuant to Rule 912.a.(5), operators nevertheless must cleanup any actual spill or release, regardless of whether it ultimately proved to fall below any of the reporting thresholds of Rule 912.b. In Rule 912.e.(2), the Commission clarified that any suspected spill or release reported pursuant to Rule 912.b.(1).G that eventually proved to exceed another reporting threshold in Rule 912.b must be cleaned up pursuant to Rule 912.c.

Rule 912.f

Consistent with the Commission adopting Rule 218, creating a new Form 9, Transfer of Operatorship, the Commission adopted a new Rule 912.f requiring the operator buying a transferred facility with an active Form 19 to file a supplemental Form 19, designating whether the buying operator or selling operator is responsible for closing open spills and releases related to the transferred facility.

Rule 913.

The Commission moved prior Rule 909, governing site investigation, remediation, and closure, to Rule 913.

Some stakeholders suggested that the Commission adopt specific standards in its 900 Series Rules to address the subsequent construction of reservoirs atop plugged and abandoned wells. The Commission did not adopt this suggestion because local governments and the federal government, rather than the Commission, are charged with regulating land use. Decisions about subsequent land uses at closed oil and gas locations and atop plugged and abandoned wells are accordingly left for local governments and the federal government, rather than the Commission, because these subsequent land uses are not "oil and gas operations" as defined in the Oil and Gas Conservation Act. *See* C.R.S. § 34-60-103(6.5). Specifically, the appropriate location for reservoirs is a decision for local governments and the Division of Water Resources, which each have regulatory authority to address the appropriate location for a reservoir. Moreover, the existence of a plugged and abandoned well beneath or in proximity to a proposed reservoir would not necessarily preclude the construction of a reservoir or other subsequent surface land uses, but may in some circumstances require additional protections to ensure that the plugged and abandoned well maintains its integrity. However, recognizing these stakeholders' concerns, the Commission directs its Staff to update its longstanding Surface Development Policy to provide guidance and identify best management practices for oil and gas location closures and plugging and abandonment of wells to avoid precluding future land uses where possible.

Rule 913.a

The Commission simplified the language of prior Rule 909.a to provide clearer guidance about what types of activities are subject to the Rule 913 investigation, remediation, and reporting requirements. This serves to clarify that ongoing reporting of remediation projects is a key purpose of the Rule. The Commission also clarified that closure operators are subject to the Commission's 1000 Series Reclamation Rules, which apply during the exercise of remediation projects (*e.g.*, for stormwater protection, surface disturbance minimization, and topsoil protection), and create additional requirements for reclaiming facilities after closure.

Rule 913.b

Rule 913.b.(1)

The Commission moved prior Rule 340 to Rule 913.b.(1), specifying the when an operator is required to submit a Form 27. Consistent with current practice, the Commission does not intend for the requirement to obtain the Director's approval of a Form 27 prior to commencing remediation operations to apply to emergency and initial response actions reported on a Form 19. Additionally, no Form 27 will be required for a spill that is not reportable pursuant to Rule 912.b.

Rule 913.b.(2)

In Rule 913.b.(2), the Commission clarified and added additional specificity to the sampling and analysis standards of prior Rule 909.b.(2). The Commission clarified that operators must remediate any contamination that is in excess of WQCC Regulation 41 numeric and narrative groundwater quality standards and classifications. The Commission determined that it was important to clarify that operators are subject to the WQCC's narrative groundwater quality standards, in addition to its numeric standards. Some stakeholders raised questions about why Rule 913.b.(2) required sampling analysis of soil and groundwater, but not surface water. The Commission determined that sampling is necessary to determine if soil or groundwater has been impacted, but impacts to surface water may be determined through other means such as a visual inspection. When surface water is threatened or impacted, the Commission will require operators to collect appropriate sampling and analysis to determine the extent of contamination and plan appropriate remediation. The Director will consult with the WQCD to determine the appropriate process and lead agency to oversee remediation in such a circumstance. The Commission also adopted specific standards for sampling and analysis methods to provide additional clarity for operators in Rules 913.b.(2).A–C. The Commission determined that clear sampling methods are necessary regardless of the final disposal location of E&P Waste subject to Rule 913.b.(2).A.

Rule 913.b.(3)

In Rule 913.b.(3), the Commission adopted new standards for the management of investigation-derived waste. Investigation-derived waste that meets the definition of E&P Waste must be managed as E&P Waste pursuant to Rule 905. Investigation-derived waste that does not meet the definition of E&P Waste must be managed as solid or hazardous waste, as appropriate, pursuant to Rule 906. The Commission determined that it was necessary to adopt standards for investigation-derived waste because its management has been an area of confusion for many operators in the past.

The Commission also adopted a new definition of Investigation-Derived Waste in its 100 Series Definitions. The Commission defined Investigation-Derived Waste to include any materials generated during site investigation and remediation activities. These may range from disposable and consumable supplies such as personal protective equipment, to native materials that are disturbed during investigation and remediation, such as soil cuttings and purged groundwater. The Commission intends for operators to manage their waste during investigation and remediation carefully so as not to mix E&P Waste with solid waste where separate treatment, disposal, or documentation is necessary to maintain compliance with all applicable regulations.

Rule 913.b.(4)

The Commission moved prior Rule 909.b.(4), governing pit evacuation, to Rule 913.b.(4), but did not substantively revise the Rule.

Rule 913.b.(5)

The Commission moved prior Rule 909.b.(5), governing general remediation standards, to Rule 913.b.(5).A. The Commission clarified the language of the Rule, and also revised it to conform to Senate Bill 19-181's changes to the Commission's mission and statutory authority. C.R.S. § 34-60-106(2.5)(a).

The Commission adopted a new Rule 913.b.(5).B, setting specific standards for remediation activities. These include fencing and covering open excavations, protecting topsoil, minimizing surface disturbance, properly storing and managing E&P Waste, and protecting wildlife for remediation activities that occur in high priority habitat. The Commission determined that it was necessary and reasonable to adopt these standards because of the Commission's experience with regulating prior remediation projects that did not conform to such standards. Many remediation activities have been conducted in a manner that caused unnecessary surface disturbance, inhibited effective reclamation, and caused adverse impacts to other resources that exceeded the environmental benefits of the remediation activities themselves. Some stakeholders requested clarification about how operators should comply with Rule 913.b.(5).B.ii's requirement to protect topsoil. The Commission instructs its Staff to issue guidance about how to implement the requirements of Rule 913.b.(5).B, including the requirement to protect topsoil. The purpose of Rule 913.b.(5).B.ii is to ensure that operators do not unnecessarily disturb, compact, or contaminate undisturbed topsoil that was not contaminated by the spill or release requiring remediation. Similarly, Rule 913.b.(5).B.iii's requirement to minimize unnecessary surface disturbance is intended to prevent operators from unnecessarily driving over or storing materials on top of surface areas that were not otherwise disturbed by the oil and gas operations requiring remediation. The guidance the Commission's Staff issues for implementing Rule 913.b.(5).B, along with information or guidance from CPW related to the Commission's 1200 Series Rules, will also provide additional details about best management practices to protect wildlife. The Director may consult with CPW to identify appropriate best management practices, where appropriate.

In Rule 913.b.(5).C, the Commission provided specific standards for determining when a Form 27 is required for impacts to groundwater. The standards set are consistent with prior Rule 909.c.(5) and the Commission's specific incorporation by reference of the WQCC's narrative groundwater in Rule 901.b. Rule 913.b.(5).C also clarifies the cleanup standards for groundwater.

Rule 913.b.(6)

The Commission moved prior Rule 909.b.(6), governing reclamation, to Rule 913.b.(6). The Commission clarified that reclamation of a site begins after closure of any open remediation projects. The Commission does not intend for Rule 913.b.(6) to serve as a substantive reclamation standard, but rather to remind operators that they still have obligations to reclaim sites pursuant to the Commission's 1000 Series Rules after remediation is complete.

Rule 913.c

The Commission moved prior Rule 909.c, governing Form 27s, to Rule 913.c. The Commission capitalized defined terms, changed the word "shall" to "will," updated cross-references to its revised Rules, and clarified confusing wording. The Commission also added several operations to the list of remediation activities that require a Form 27, including closure of all pits, rather than just the subset that previously required a Form 27; removal of buried or partially buried vessels required by prior Rule 905; and remediation of natural gas in soil or groundwater.

In Rule 913.c.(8), the Commission authorized the Director to request a Form 27 due to potential risks to soil, surface water, or groundwater. Some stakeholders suggested that Rule 913.c.(8) was overly broad because it authorizes the Director to request Form 27 submissions for potential, rather than actual, risks to soil, surface water, and groundwater. The Commission determined that it was necessary to include the word "potential" in Rule 913.c.(8), because Form 27s govern not only remediation, but also investigation, and whether actual risks to resources exist may not be known at the time a Form 27 is requested. Therefore investigation would be necessary.

In Rule 913.c.(9), the Commission required a Form 27 submission for decommissioning oil and gas facilities. Consistent with Rule 911.a, the Commission intends for operators to submit a final Form 27 to verify that there are no residual impacts from production at an oil and gas location at the end of the facility's lifetime and before financial assurance is released. The Commission intends for operators to submit a Form 27 during plugging and abandonment activities for closure of related production facilities and for the removal of flowlines. The Commission does not intend for operators to submit Form 27s for modifications to a facility that is not being completely decommissioned, such as removal of a single tank from a location that otherwise still has active oil and gas operations. However, a Form 27 may be required for significant changes to an existing location that involve remediation activities, such as removing an entire tank battery and converting to a tankless production facility.

Rule 913.d

The Commission adopted a new Rule 913.d, requiring an implementation schedule for the Form 27. The Commission determined that including a specific and enforceable implementation schedule on a Form 27 is necessary to ensure that remediation activities occur in a timely manner. In Rule 913.d.(1), the Commission specified that operators must investigate impacts to soil, groundwater, and surface water as soon as they are discovered, to convey the Commission's intent that remediation activities begin promptly, regardless of any final deadlines in the implementation schedule.
In Rule 913.d.(2), the Commission required operators to obtain the Director's approval for changes in the approved remediation schedule at least 14 days in advance. The Commission determined that this is sufficient time for the Commission's Staff to review change requests, while also allowing operators flexibility to account for changing circumstances such as unexpected weather conditions or encountering unexpected contamination. As of June 2020, operators had nearly 1,500 active remediation projects statewide, many of which have gone long periods of time with no activity or reporting. Rule 913.d ensures that operators will diligently pursue timely closure of projects which may otherwise go stale.

Some stakeholders suggested that the Commission adopt a firm limit on the duration of remediation projects, or suggested that the Commission increase the financial assurance required for remediation projects. The Commission determined not to address this question in the 800/900/1200 Mission Change Rulemaking because the duration of a remediation project will vary depending on site-specific circumstances, and may range from several months to several years. However, the Commission recognizes the importance of limiting the duration of remediation projects because environmental contamination persists until the remediation project is completed. The Commission will therefore consider the question of whether it will require operators to provide financial assurance if remediation is not complete within a specific timeframe in its forthcoming Financial Assurance Rulemaking.

Rule 913.e

The Commission adopted a new Rule 913.e, governing the reporting schedule for open Form 27s. The Commission determined that a reporting schedule is necessary because the Commission oversees many open remediation projects that have languished for years without progress towards final remediation goals. Consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), the Commission determined that it was necessary to adopt stronger oversight and more frequent reporting on remediation projects to ensure they are completed in a timely manner, in order to protect public health, safety, welfare, the environment, and wildlife from unremediated spills and releases. Rule 913.e specifically requires operators to provide quarterly updates on open remediation projects by submitting a supplemental Form 27, unless the Director approves an alternate reporting schedule, which may require reporting more or less frequently than quarterly.

In Rule 913.e.(2), the Commission required all operators with open remediation projects approved prior to the effective date of the 800/900/1200 Mission Change Rulemaking to submit a supplemental Form 27 to the Director detailing the status of the project within three months of the 800/900/1200 Mission Change Rulemaking's effective date. An industry trade association suggested that the Commission provide each operator with a report of all the operator's open remediation projects. The Commission determined that this is unnecessary because it is the Commission's expectation that all operators are aware of all open remediation projects for which they are responsible and it is not an effective use of Commission Staff's time to prepare a remediation report for every operator in the State. Operators may also create their own open remediation project lists using publicly available information on the Commission's website. This will serve as an initial quarterly report and provide the Commission's Staff with a baseline to evaluate future quarterly progress reports against. The Commission determined that three months was a reasonable timeframe for an initial report to be submitted, because it aligns with the quarterly reporting timeframe that will be required for future reports.

Rule 913.f

Consistent with Rule 911.b, the Commission adopted standards for reporting spills and releases discovered during closure processes.

Rule 913.g

Consistent with the Commission adopting Rule 218, creating a new Form 9, the Commission adopted a new Rule 913.g requiring the operator buying a transferred facility with an active Form 27 to file a supplemental Form 27, designating whether the buying or selling operator is responsible for open remediation projects.

Rule 913.h

The Commission moved prior Rule 909.e, governing closure of remediation projects, to Rule 913.h, and substantially revised the standards to provide clearer standards for remediation project closure.

In Rule 913.h.(1), the Commission specified the three criteria with which operators must demonstrate compliance for remediation to be complete: Table 915-1's cleanup concentrations, WQCC numeric and narrative groundwater quality standards, and any other conditions of approval on a Form 27.

In Rule 913.h.(2), the Commission authorized operators to seek a variance from the Commission pursuant to Rule 502 to comply with an alternate standard instead of the standards listed in Rules 913.h.(1).A and C. The Commission recognizes that local soil characteristics vary across the state and intends for operators to be able to obtain a disposition to comply with alternate standards so long as those alternate standards are at least as protective as the standards in Rules 913.h.(1).A and C. Because the WQCC has sole jurisdiction to classify groundwater, the Commission cannot grant variances to WQCC Regulation 41, and therefore the Commission will not grant variances to Rule 913.h.(1).B.

In Rule 913.h.(3), the Commission provided that remediation projects which are subject to periodic monitoring may not be closed until four consecutive quarters of modeling demonstrate compliance with the standards in Rule 913.h.(1). The Commission determined that four consecutive quarters is an appropriate timeframe because groundwater quality may vary over time and seasonally, and four quarters of consecutive sampling reduces the risk of prematurely declaring a remediation project to be closed. This is consistent with best practices used for site closure in other regulatory programs.

In Rule 913.h.(4), the Commission clarified prior Rule 909.e.(2)'s standards for notification of completion of remediation projects, to ensure that both the Commission's Environmental Protection Specialists and Reclamation Staff receive appropriate notice and that remediation project status is appropriately changed to "closed" in recognition of completion of the work.

Rule 913.i

The Commission moved prior Rule 909.f, governing financial assurance for remediation projects, to Rule 913.i, but did not revise the Rule. The Commission intends to address Rule 913.i in its forthcoming Financial Assurance Rulemaking.

Rule 914.

The Commission moved prior Rule 324D, governing criteria to establish points of compliance, to Rule 914. The Commission capitalized defined terms and revised the language of the Rule to be consistent with Senate Bill 19-181's changes to the definition of minimize adverse impact. C.R.S. 34-60-103(5.5). The Commission also clarified two confusing terms in Rule 914.b. First, the Commission changed the term "velocity" to "hydraulic conductivity," which covers both porosity and permeability and is a more appropriate standard to apply. Second, the Commission changed the term "climate" to "any seasonal hydrologic variability" to clarify the relevance of local climate considerations to a site's hydrologic characteristics.

The Commission revised Rule 914.a to better reflect WQCC groundwater standards and classifications. Rather than considering quality, quantity, potential economic use, and accessibility of unclassified water, the Commission intends for the Director to instead apply the WQCC's interim narrative standards to protect domestic and agricultural groundwater uses.

Rule 915.

The Commission moved prior Rule 910 to Rule 915, and Table 910-1 to Table 915-1.

Rule 915.a

The Commission moved prior Rule 910.a, governing soil and groundwater concentrations, to Rules 915.a and 915.c. In Rule 915.a, the Commission provided specific standards for soil cleanup concentrations.

Rule 915.a is one of several changes the Commission made to both Rule 915 and Table 915-1 because Table 915-1 included several contaminant concentrations that originated in an outdated CDPHE document. That document, CDPHE's HMWMD's Table 1 – Colorado Soil Evaluation Values (December 2007), is no longer in use. The HMWMD updated the document in 2011, but later discontinued using it as a standard for soil and groundwater contaminant cleanup concentrations. In lieu of the Colorado Soil Evaluation table, in 2015 HMWMD began using the EPA's Regional Screening Levels ("RSLs") for Chemical Contaminants at Superfund Sites. Accordingly, the Commission updated Table 915-1 to also incorporate the EPA's RSLs, and incorporated EPA's RSLs by reference in Rule 901.b and Table 915-1 footnote 6. EPA's RSLs set different cleanup standards for different contexts. Table 915-1 accordingly incorporates separate standards for cleanup of soil that has no pathway for communication with groundwater, and soil for which a pathway to groundwater exists. Additional information is provided in Table 915-1 footnote 7. The Commission instructs its Staff to issue guidance about how the Director will determine whether the residential soil standard or groundwater standard applies on a case-by-case basis.

Rule 915.a establishes a presumption that EPA's RSL soil screening levels will apply, and that EPA's groundwater soil screening levels will only apply where evidence shows that a pathway to groundwater exists. Some stakeholders suggested that the Commission adopt EPA's standards for non-residential soils. The Commission adopted EPA's standards for residential soils based on consultation with CDPHE, and therefore determined that these standards are appropriate. Additionally, although not all oil and gas operations occur in residential areas, land use changes over time mean that a remediated area may be subject to residential land uses in the future.

Rule 915.b

The Commission adopted a new Rule 915.b, governing soil suitability for reclamation, because Table 915-1 is used for both remediation and reclamation purposes. Consistent with adopting Rule 915.b, the Commission also added a subheading to Table 915-1 to specifically identify the category of cleanup concentrations intended ensure that soil is suitable for reclamation. Prior to the 800/900/1200 Mission Change Rulemaking, the Commission addressed soil suitability for reclamation through prior Table 915-1, guidance, and a list of "frequently asked questions" established by the Commission's 2008 House Bill 07-1341 rulemaking. Codifying these standards provides clearer regulatory expectations for operators and improves regulatory certainty. The Commission also amended the soil suitability for reclamation standards in Table 915-1 based on evidence in the administrative record, including sources cited in Table 915-1 footnotes 2 and 3, and incorporated by reference in Rule 901.b. Additionally, the Commission relied on the expertise of its Staff, which include multiple specialists with doctorates in relevant fields, including geochemistry and restoration ecology.

Rule 915.c

As discussed above, the Commission adopted a new Rule 915.c to provide clear standards for groundwater cleanup concentrations. The Commission derived the groundwater cleanup concentrations in Table 915-1 from the WQCC's Regulation 41 numeric and narrative groundwater quality standards and classifications.

Rule 915.d

The Commission adopted a new Rule 915.d to authorize the Director to require operators to analyze soil or groundwater for additional contaminants of concern on a case-by-case basis. Although Table 915-1 provides cleanup concentrations for numerous potential contaminants, the Commission recognizes that there are compounds beyond those included on Table 915-1 that may be important for operators to analyze to ensure that remediation activities appropriately protect the environment from all contaminants released by oil and gas activities.

Some stakeholders raised questions about whether the Commission would require operators to address per- and polyfluoroalkyl substance ("PFAS") contamination at oil and gas locations. Although oil and gas operations, and the products produced by oil and gas operations, do not themselves contain PFAS, it is possible that some firefighting foams used at an oil and gas location could contain PFAS. The Commission therefore determined that it would be necessary and reasonable to authorize the Director to require additional sampling as appropriate for PFAS where the Director has reason to believe that firefighting foam known to contain PFAS was used at an oil and gas location.

In Rules 915.d.(1) & (2), the Commission authorized the Director to require operators to conduct additional sampling for specific elements, compounds, and parameters. Rule 915.d.(1) references the WQCC's Regulation 41 numeric groundwater quality standards. Rule 915.d.(2) references the WQCC's Regulation narrative groundwater quality standards found in 5 C.C.R. § 1002-41:41.5.A. The WQCC's numeric and narrative groundwater quality standards apply to protect groundwater in Colorado irrespective of the Commission's Rules. However, consistent with its obligations as an implementing agency pursuant to C.R.S. § 25-8-202(7)(a), the Commission specifically enumerated the WQCC Regulation 41 and subpart 41.5 standards in Rule 915.d. The Commission did not include wildlife resources among the list of factors to be considered pursuant to Rule 915.d.(2), because the standard is based on WQCC Regulation 41, which does not specifically enumerate wildlife resources. *See* 5 C.C.R. § 1002-41:41.5.A.1.

Rule 915.e

In Rule 915.e, the Commission substantially revised prior Rule 910.b, governing sampling and analysis methods. The Commission incorporated EPA's SW-846 analytical methods by reference in Rules 915.e and 901.b. The Commission will also allow operators to use analytical methods published by other nationally-recognized standards organization with the Director's approval on a case by case basis. For the soil suitability parameters in Table 915-1, the Commission required the use of specialized agricultural analytical methods, including the Western Coordinating Committee on Nutrient Management's Soil, Plant, and Water Reference Methods for the Western Region, which the Commission incorporated by reference in Rule 901.b and Table 915-1 footnote 2. The Commission further required that sampling and analysis only occur at state or nationally accredited laboratories, or, for soil suitability parameters, a lab with experience in agricultural analyses.

The Commission recognizes that the sampling and analytical methods in Rule 915.e are different than the sampling and analytical methods required by prior Rule 910.b. Beginning on the effective date of the 800/900/1200 Mission Change Rulemaking, the Commission will require all sampling and analysis to adhere to the standards in Rule 915.e. Thus, an operator will be required to adhere to the sampling methods prescribed in Rule 915.e even for remediation projects approved on a Form 27 prior to the effective date of the 800/900/1200 Mission Change Rulemaking. Although the Commission intends for all future sampling processes to adhere to the standards in Rule 915.e, pursuant to Rule 915.f, operators may seek the Director's approval to adhere to the substantive cleanup concentrations in prior Table 910-1 for any remediation projects already in process as of the effective date of the 800/900/1200 Mission Change Rulemaking. Consistent with this intent, the Commission moved prior Rule 910.b.(1), governing existing workplans, to Rule 915.f.

Rule 915.e.(1)

The Commission moved prior Rule 910.b.(2), providing methods for sampling and analysis, to Rule 915.e.(1), but made relatively few changes to the Rule. In Rule 915.e.(1).A, the Commission clarified that operators must provide records of field measurements and tests to the Director upon request and enumerated the specific categories of documents that the Director may request. In Rule 915.e.(1).B, the Commission clarified that samples must be delivered to a laboratory under a chain-of-custody protocol as is appropriate for documenting proper handling of samples following collection but prior to lab analysis. In Rule 915.e.(1).C, the Commission removed API RP 45 as a sampling method that operators may use but maintained the EPA SW-846 sampling method. And in Rule 915.e.(1).D, the Commission clarified that background samples should be taken outside the area disturbed by oil and gas operations.

Rule 915.e.(2)

The Commission moved prior Rule 910.b.(3), governing soil sampling and analysis, to Rule 915.e.(2). The Commission reworded Rule 915.e.(2).A to improve clarity, but did not substantively revise the Rule. Although Rule 915.e.(2).A was substantively unchanged, some stakeholders raised questions about whether Rule 915.e.(2).A applies to stray gas in soil. Consistent with its interpretation of prior Rule 910.b.(3), the Commission intends to continue applying Rule 915.e.(2).A to stray gas in soil.

In Rule 915.e.(2).B, the Commission clarified that operators must take a sufficient number of samples from enough locations to determine both the vertical and horizontal extent of the impact. The Commission instructs its Staff to issue guidance about how to select an appropriate number and location of samples.

In Rule 915.e.(2).C, the Commission continued to allow operators to request that the Director modify the list of soil contaminants of concern listed on Table 915-1, based on site-specific E&P Waste profiles and process knowledge. The Commission intends that the Director may only approve a change to the list of contaminants of concern in Table 915-1 if doing so is equally or more protective of air, water, soil, and biological resources. To obtain approval of an alternate standard pursuant to Rule 915.e.(2).C, the Commission intends that an operator would need to demonstrate that a specific contaminant of concern is not present or that there is other reason to believe that a specific contaminant should not be analyzed at a given location. Rule 915.e.(2).C, which governs requests for alternative *contaminants*, is distinct from Rule 913.h.(2), which governs alternative *concentrations*.

In Rule 915.e.(2).D, the Commission made minor changes to the Rule's wording to reflect that soil suitability for reclamation standards are included in Table 915-1. Some stakeholders questioned how operators could obtain a soil background sample without permission from a nearby surface owner. If an operator is unable to obtain consent from a nearby surface owner to conduct background sampling, then the operator must adhere to the otherwise applicable standards in Table 915-1, or seek a variance pursuant to Rule 502.

Rule 915.e.(3)

The Commission moved prior Rule 910.b.(4), governing groundwater sampling, to Rule 915.e.(3). The Commission did not substantively revise Rule 915.e.(4).A, which specifies the circumstances in which groundwater sampling and analysis protocols are applicable.

The Commission revised Rule 915.e.(3).B to clarify that samples must be taken as soon as possible, and at areas near the suspected source of the impact. This requirement is necessary to prevent operators from evacuating substantial volumes of contaminated groundwater from an excavation—effectively conducting remediation—prior to collecting appropriate samples to characterize the nature of contamination. The Commission also specified that the Director may require operators to install temporary or permanent monitoring wells if necessary for sample collection. This requirement is necessary where groundwater may flow either too slowly or too quickly from a non-impacted area into an excavation to allow for adequate characterization, or where there is a site-specific need to determine groundwater gradient.

In Rule 915.e.(3).C, the Commission allowed operators to request that the Director modify the list of groundwater contaminants of concern listed on Table 915-1, based on site-specific E&P Waste profiles and process knowledge. The Commission intends for this exception to be narrow, and not frequently used. The Commission intends that the Director may only approve a change to the list of contaminants of concern in Table 915-1 if doing so is equally or more protective of air, water, soil, and biological resources. To obtain approval of an alternate standard pursuant to Rule 915.e.(3).C, the Commission intends that an operator would need to demonstrate that a specific contaminant of concern is not present or that there is other reason to believe that a specific contaminant should not be analyzed at a given location. Rule 915.e.(3).C, which governs requests for alternative *contaminants*, is distinct from Rule 913.h.(2), which governs alternative *concentrations*, and does not allow a variance, because the groundwater concentrations in Table 915-1 are set by WQCC Regulation 41, not the Commission.

The Commission clarified the wording of Rule 915.e.(3).D, but did not substantively revise the Rule.

Rule 915.e.(4)

The Commission adopted a new Rule 915.e.(4), governing sampling and analysis of waste and produced fluids. Rule 915.e.(4) authorizes the Director to require operators to collect samples of various substances, including forms of E&P Waste, where necessary and reasonable to characterize the waste or other information necessary to provide oversight over a remediation process. Some stakeholders raised questions about the timing for obtaining the Director's approval for sampling protocols pursuant to Rule 915.e.(4). The Commission's Staff will continue to timely process remediation plans to protect the environment, recognizing that delays in remediation application processing may result in increased spread of environmental contaminants. The Commission intends for its Environmental Protection Specialist Staff to prioritize their resources towards efficient processing of remediation applications.

Rule 915.f

The Commission adopted a new Rule 915.f, governing remediation projects in progress at the time the 800/900/1200 Mission Change Rules become effective. Rule 915.f provides clear standards for remediations projects that were already in progress subject to an approved Form 27 as of the effective date of the 800/900/1200 Mission Change Rulemaking. Operators of such remediation projects may request the Director's approval to comply with prior Table 910-1, rather than Table 915-1. However, if remediation is not complete within one year of the effective date of the 800/900/1200 Mission Change Rulemaking, then the Commission intends for the operator to comply with Table 915-1. The Commission intends for the Director to exercise appropriate discretion on a case-by-case basis, and to consider appropriate time allowances to achieve closure under both regimes, to determine whether unique characteristics of each individual remediation project warrant application of prior Table 910-1 standards or Table 915-1 standards.

Table 915-1

As discussed above, the Commission moved prior Table 910-1 to Table 915-1, and updated it to reflect the November 2020 version of EPA's RSLs. Many stakeholders questioned why the Commission used EPA's RSLs as the basis for Table 915-1's contaminant concentrations. The Commission uses these values because the HMWMD uses EPA's RSL values, as discussed in CDPHE's applicable guidance. *See* CDPHE, *Air, Water, and Soil Remedial Objectives*, https://www.colorado.gov/pacific/cdphe/air-water-soil-remedial-objectives (last visited Nov. 18, 2020). CDPHE has discontinued the use of its in-house generated tables, including the CSEV table that was the basis for prior Table 910-1. Accordingly, to maintain consistency with CDPHE practice, and based on extensive consultation with HWMWD staff, the Commission determined that it is appropriate to follow CDPHE's lead and utilize

EPA's RSL values in Table 915-1. Because EPA's RSL includes multiple target risks ("TR") and target hazard quotients ("THQ"), the Commission specified which TR and THQ values are used in footnote 10 to Table 915-1. The Commission chose a TR of $1x10^{-6}$ and a THQ of 0.1 for organic compounds because EPA's frequently asked questions document for the RSLs indicates that these values are appropriate when it is likely that there is more than one compound of concern present, which is typically the case for soil or groundwater impacted by spills and releases of hydrocarbon containing substances and produced water.

Consistent with moving prior Table 910-1 to Table 915-1, the Commission revised its 100 Series definition of Remediation to update the cross-reference to Table 915-1. The Commission consulted with HMWMD about whether to align the two agencies' definitions of the term "Remediation." The Commission determined that such alignment was unnecessary given the different purposes and functions of each agency's definition. The Commission accordingly did not substantively revise its 100 Series definition of Remediation.

Some stakeholders raised questions about specifying that soil TPH should include both total volatile hydrocarbons in the C_6 to C_{10} range and extractable hydrocarbons in the C_{10} to C_{36} range. This is not a change from prior Table 910-1 identifying TPH (total volatile and extractable petroleum hydrocarbons) as a contaminant of concern. The Commission revised Table 915-1 to more clearly define total volatile and extractable hydrocarbons, but continues to expect operators to analyze samples for all C_6 through C_{36} range hydrocarbons. The Commission recognizes that some laboratories may not conduct analyses beyond C_{28}, but there are numerous accredited labs nationwide that routinely provide results through C_{36}. Table 915-1 does not dictate analytical methods, but rather specifies contaminants of concern. The Commission recognizes that not all laboratories use the same classifications for hydrocarbon ranges, and if a laboratory classifies ranges of hydrocarbons using a different nomenclature than the Commission, operators may utilize the services of that laboratory so long as the laboratory can test for hydrocarbons in the full C_6 through C_{36} range. However, if a laboratory is unable to test for hydrocarbons in the full C_6 through C_{36} range, then an operator must utilize the services of a different laboratory. The Commission set the standards in Table 915-1 based on EPA's RSLs, and therefore determined that it would be inappropriate to adjust EPA's carefully calibrated risk-based standards based on the capabilities of any individual laboratory. However, as discussed in footnote 9, whenever the practical quantitation limit ("PQL") for a pollutant is higher (less stringent) than the threshold concentration listed in Table 915-1, the PQL should be used. The Commission instructs its Staff to address the meaning of a PQL in a guidance document. The Commission chose not to specify what qualifies as a PQL in the regulatory text because PQLs change over time as laboratory technology evolves. The Commission instructs its Staff to keep its guidance about PQLs for various pollutants up to date, based on the reasonable determination that evolving technologies have established a new PQL for an individual pollutant.

Some stakeholders also raised questions about the "below visual detection limit" standard for liquid hydrocarbons including condensate and oil. The Commission intends for the visual detection limit standard to be a backup provision for the quantitative standard for hydrocarbons—500 milligrams per kilogram TPH. The Commission determined that including a clear criteria that is readily identifiable by operators and the Commission's Field Inspectors and Environmental Protection Specialists is a reasonable backup standard for the quantitative TPH standard. Visual detection is a reasonably objective standard that is frequently used in other regulatory contexts.

Some stakeholders also raised questions about why the Commission reduced the maximum pH standard from 9 to 8.3. The Commission reduced the maximum pH standard because soil pH must be at a lower level to support reclamation and plant and bacterial growth, as opposed to the drinking water standard that was included in prior Table 910-1, for which a higher maximum pH was appropriate. Some stakeholders suggested that the maximum soil pH standard was inappropriate based on an average of soil samples from different locations. The Commission does not consider this to be a reasonable indication of background concentrations, because plant growth is governed by site-specific soil characteristics, not average regional concentrations. If there is a higher background level of pH at an individual site, then this can be considered on a site-specific basis. However, the Commission determined that the pH level in Table 915-1 should be based on typical plant growth characteristics, not based on a regional average background level of soil pH.

The Commission revised several of the soil suitability for reclamation standards in Table 915-1. The purpose of these standards is to set parameters to ensure that remediated areas may be used for future agricultural or other vegetation growth purposes, not to protect human health. Consistent with its statutory duties to address reclamation, the Commission adopted soil standards intended to facilitate future vegetation growth, and to prepare remediation sites for reclamation to reclaim the area for either crop growth or rangeland. Soil suitability for reclamation depends on numerous factors, including conductivity, SAR, boron concentrations, and pH. All of these characteristics are synergistic, and all must be in the appropriate ranges for vegetation to grow.

Several stakeholders raised questions about the standard for boron in Table 915-1. Although the Commission previously set a standard for boron as a metal in soil in prior Table 910-1, because boron is an important micronutrient in soil ecology, the Commission adopted a boron standard to ensure that soil is suitable for reclamation in Table 915-1. The Commission also adopted the standard for boron to update its Rules to use current standards and appropriate testing methods. Table 915-1 footnote 3 explains that the Director may approve modifications to Table 915-1's SAR levels and concentration for hot water-soluble boron based on land use, depth, or characteristics of the vegetative community, which takes into account background variation. The Commission will authorize modifications to the boron concentrations in Table 915-1 based on site-specific background concentrations, not standardized estimates of region-wide background levels. Some stakeholders suggested that crops grown in Colorado are not sensitive to boron, but this is contrary to evidence in the administrative record and the experience of the Commission's Staff. Staff reviewed multiple published scientific studies demonstrating the effect of boron on crops commonly grown in Colorado, including corn, wheat, and fruit crops commonly grown on the Western Slope, such as peaches, grapes, cherries, and apples.

Some stakeholders also raised questions about the threshold of 6 as the sodium adsorption ratio ("SAR") in Table 915-1. In the Commission's experience with hundreds of remediation projects in the past, and based on the expertise of its Staff scientists, 6 is the appropriate SAR standard because it is the best standard to facilitate vegetation growth. The Commission recognizes that other jurisdictions and entities recommend a standard of 13 for SAR, but this value is based on disposal of produced waters and spills at sodic (saline) sites, and is not specific to any one crop—it is merely an upper limit of the most saline that soil may be in order to facilitate *any* vegetation growth. Most crops will not grow in soil with an SAR of 13, and common crops such as corn require an SAR of less than 6 to grow.

Some stakeholders also raised questions about the cleanup concentrations for certain organic compounds in groundwater, including BTEX. Consistent with its obligations as an implementing agency pursuant to C.R.S. § 25-8-202(7)(a), the Commission continued to reference the WQCC Regulation 41 BTEX standards for drinking water.

Numerous stakeholders raised questions about appropriate procedures when background metal concentrations in soil exceed the cleanup concentrations in Table 915-1. As specified in Table 915-1 footnote 1, the Director will consider alternative cleanup concentrations for all metals in soils based on site-specific background concentrations or reference levels in nearby soil and groundwater. Footnote 1 applies to all metals in soils, rather than applying only to specific metals in the list. Additionally, footnote 11 applies to the standards for all metals in soils, and specifies that the Commission's Staff will consider applying residential soil screening level concentrations up to 1.25 times the site-specific background levels on a case by case basis. The Commission determined that together, footnotes 1 and 11 are an appropriate mechanism to address variations in background metal concentrations in different soil regions.

Ultimately, the Commission adopted the RSLs in Table 915-1 because its prior Table 910-1 used cleanup concentrations derived from guidance that is no longer in use by CDPHE. Because CDPHE's HMWMD uses EPA's RSLs as standards for soil cleanup concentrations, the Commission determined that it was appropriate to defer to EPA's

RSL of 0.68 milligram per kilogram for arsenic in residential soils. Numerous stakeholders specifically requested that the Commission adopt a standard of 11 milligrams per kilogram for arsenic as a representative statewide background concentration. The Commission chose not to adopt any statewide standard background value, because a statewide background concentration would not adequately address local or regional variability, or allow for site-specific background determinations.

Relatedly, some stakeholders suggested that the Commission adopt basin-wide background concentration levels for individual contaminants other than arsenic. The Commission did not adopt this suggestion because the basin-wide scale for background concentrations is not relevant. Soil characteristics vary greatly across geographic scales, and the geographic scale of an entire oil and gas basin is not a scientifically relevant scale for determining background concentrations. Accordingly, the Commission will determine appropriate background concentrations on a site-by-site basis, which is the scientifically appropriate geographic scale for background concentrations in soil.

1200 Series – Protection of Wildlife Resources

The passage of Senate Bill 19-181 necessitated an update of the Commission's wildlife rules. In addition to the overarching elevation of protections for public health, safety, welfare, the environment, and wildlife resources, C.R.S. § 34-60-106(2.5)(a), the legislation also modified two requirements directly impacting the Commission's oversight of oil and gas operations which have the potential to impact wildlife resources. First, Senate Bill 19-181 modified the mitigation requirements appropriate for permit conditions in the habitat stewardship rules. C.R.S. § 34-60-128(3)(b). Second, the legislation clarified the hierarchy for minimizing impacts from oil and gas operations by directing the Commission to first avoid impacts, then seek to minimize impacts, and finally to mitigate those impacts. C.R.S. § 34-60-103(5.5). Complementary to this hierarchy is Senate Bill 19-181's mandate that the Commission, at a minimum, adopt an alternative location analysis process and specify criteria used to identify oil and gas locations that are proposed to be located near populated areas. C.R.S. § 34-60-106(11)(c)(I). Given the importance of the directive to avoid impacts, the Commission also proposed an alternative location analysis consideration for wildlife resources because alternative location analyses are among the best tools available to avoid impacts. Finally, some of the updates to the 1200 Series address Senate Bill 19-181's requirement that the Commission "evaluate and address the potential cumulative impacts of oil and gas development." C.R.S. § 34-60-106(11)(c)(II).

Importantly, the Commission undertook substantial revisions to the wildlife rules to conform with changes to permitting and other processes proposed in the 200–600 and 800/900/1200 Mission Change Rulemakings and to incorporate changes it has been planning for its wildlife rules since 2013. Organizationally, the Commission tried to locate most of the process-oriented rules in the 300 Series with the 1200 Series providing more of the substance.

As discussed above, one of the primary purposes of the 800/900/1200 Mission Change Rulemaking is to implement the changes to the Commission's mission and statutory authority in C.R.S. § 34-60-106(2.5)(a). *See* C.R.S. §§ 34-60-104(1)(b), 34-60-104.3(5), 34-60-106(1)(f)(III) (referencing "rules required to be adopted by section 34-60-106(2.5)(a)"). The Commission has approached these Rules from the perspective of what measures are necessary and reasonable in order to implement the mandate of Senate Bill 19-181. Pursuant to the Act, the Commission must "regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources." C.R.S. § 34-60-106(2.5)(a). As mentioned in the Statutory Authority section above, the Commission did not make significant changes to its approach to protecting biological resources. Attachment 5 details how the Commission's prior and newly-adopted Rules collectively protect and minimize adverse impacts to biological resources.

The Commission and CPW prepared a Frequently Asked Questions ("FAQ") document to provide context for some of the changes being proposed during the rulemaking. The FAQ for the October 9, 2020 draft Rules is attached as Attachment 1. The Commission intends for the document to evolve and be updated as questions arise from stakeholders as the Rules are implemented, and not remain static as incorporated by this Statement of Basis & Purpose. Therefore, the Commission directs Staff to update and re-release Attachment 1 as a guidance document to reflect the 1200 Series Rules as adopted. As with other changes to the Commission's Rules, the revisions to the wildlife provisions are designed to encourage early communication, in this case with CPW, and landscape-level planning.

Definitions.

The changes to the Commission's 100 Series Definitions can be grouped into three different areas: species and habitat identification, mitigation hierarchy, and wildlife planning. The FAQ provides additional information about these changes.

Species and Habitat Identification. The Commission modified the definition of Wildlife Resources to clarify that the purpose of protecting Wildlife Resources is to ensure sustainable, robust wildlife populations. To that end, the Commission developed a definition for High Priority Habitat, which focuses on ensuring healthy wildlife populations by deferring to the expertise of CPW in identifying the species and habitats for which avoiding, minimizing, and mitigating impacts is critical based on the best available science. In adopting this definition, the Commission chose to use High Priority Habitat as the criteria to initiate certain permitting or review processes and substantive standards in its 300, 400, 900, and 1200 Series Rules. High Priority Habitat is an accepted CPW term that provides certainty that there is known geographic distribution of the habitat and species, impacts from development (oil and gas or otherwise) are well understood, and there is consensus on effective measures to protect the resource. With this change, the definitions of Restricted Surface Occupancy Area and Sensitive Wildlife Habitat were no longer needed, and therefore, the Commission removed these definitions from its 100 Series Rules.

Maps showing and spatial data identifying the individual and combined extents of the High Priority Habitat areas have been provided by CPW and attached to the 1200 Series Rules as Appendix VII. The Commission will continue to provide these maps on its website. The Commission intends to coordinate with CPW to determine the current and relevant data upon which it will base the High Priority Habitat maps. The extent of these High Priority Habitat areas will be subject to update on a periodic, but no more frequent than annual, basis and will be modified only through the Commission's rulemaking process described in Rule 529. As provided in the 100 Series definition for High Priority Habitat, the Commission will notice the rulemaking proceeding by January 15 of each year with the intent of updating the maps and spatial data annually.

To ensure that operators are able to efficiently plan their developments, the

Commission intends that map updates will generally not apply to any Form 2A, Oil and Gas Location Assessment, oil and gas development plan, or comprehensive area plan deemed complete prior to the commencement of the map update rulemaking hearing. However, there may be certain circumstances where a Form 2A, oil and gas development plan, or comprehensive area plan deemed complete may warrant reevaluation by the Commission in order to conform with current and relevant High Priority Habitat data, which will be evaluated on a case-by-case basis, as appropriate, in consultation with the operator and CPW.

The Commission is committed to providing timely and accurate map updates, as operators statewide will rely on the High Priority Habitat maps to inform their oil and gas siting decisions. As explained in more detail below, Rules 309.e.(2).D and 309.e.(3).C provide "onramps" and "offramps" to consultation with CPW in order to ensure related protections for wildlife resources in the 1200 Series Rules can be appropriately applied. The Commission recognizes that, even with annual rulemaking, wildlife or habitat may change as they are dynamic elements and maps will necessarily remain static. The Commission also understands the importance of employing the mitigation hierarchy to address different wildlife habitats that are currently not mapped as part of High Priority Habitat, which include, but are not limited to, pinch points or bottlenecks, and stopover areas within big game migration corridors. The Commission acknowledges its role, along with CPW and other state agencies, to implement Executive Order D 2019-011 – Conserving Colorado's Big Game Winter Range and Migration Corridors. With respect to pinch points or bottlenecks, and stopover areas within big game migration corridors, the Commission recognizes the importance of avoiding development in these areas to the extent they are known. Accordingly, the Commission will review emerging wildlife habitat data provided by CPW and will consider incorporating such information, as appropriate, as part of future High Priority Habitat map rulemaking proceedings.

Mitigation Hierarchy. In implementing the clarified mitigation hierarchy, the Commission chose to define Avoid Adverse Impacts, Minimize Adverse Impacts, Mitigate Adverse Impacts, and Unavoidable Adverse Impacts. The Commission believes the additional clarity provided by these definitions will assist stakeholders in understanding how the Commission will review proposed oil and gas operations. Importantly, the Commission defined the term Unavoidable Adverse Impacts to articulate how it would address those residual impacts that remain even after the Commission has considered the opportunity and ability to avoid impacts and has included site-specific measures to minimize impacts. Consistent with these changes, the Commission removed its prior 100 Series definition of Mitigation, which it replaced with the newly defined term, Mitigate Adverse Impacts.

Some stakeholders raised a question about the Commission's decision to include a definition in the regulatory text for Minimize Adverse Impacts, as this is a term also defined in the statute. C.R.S. § 34-60-103(5.5). The term as defined in the statute sets forth the mitigation hierarchy by directing the Commission to first avoid impacts, then seek to minimize unavoidable impacts, and finally to mitigate those unavoidable and adverse impacts. However, the statutory definition of "minimize adverse impacts" contains the word "minimize." The Commission's definition of Minimize Adverse Impacts as it appears in the regulatory text is not intended to re-define the statutory term "minimize adverse impacts." Instead, the Commission's definition is intended to define minimize adverse impacts as it is understood within the mitigation hierarchy of the statutorily defined term. That is, the Commission is defining the undefined terms within the statutory definition.

Wildlife Planning. The Commission defined the following three terms to provide clarity regarding the different tools available when operators are planning for and addressing wildlife impacts through the mitigation hierarchy: Compensatory Mitigation Plan, Wildlife Mitigation Plan, and Wildlife Protection Plan. Throughout the Mission Change Rulemaking, the Commission revised its Rules to emphasize the importance of planning for impacts, which includes consideration of identifying impacts and then applying the mitigation hierarchy to reduce impacts. The Commission recognizes that the paths to planning for impacts to wildlife resources can take the shape of numerous documents and can be undertaken in concert with the federal government planning, local government planning, or surface owner preferences. By creating breadth in the definitions and types of plans, the Commission encourages operators to incorporate landscape-level planning into their consideration of wildlife resources and to include CPW in early stages of planning for development, including in any on-site evaluations conducted for other agencies.

Rule 304.b.(2).B.viii.

Senate Bill 19-181 amended the definition of "minimize adverse impacts," which directs the Commission to "avoid adverse impacts from oil and gas operations" wherever that statutory term is used. C.R.S. § 34-60-103(5.5)(a). The alternative location analysis is the Commission's primary, and best, tool to avoid adverse impacts, because the most effective way to avoid adverse impacts is through siting decisions. Accordingly, C.R.S. § 34-60-103(5.5)(a) provides independent statutory authority for the Commission to adopt an alternative location analysis process as a tool for avoiding any category of adverse impacts.

The Commission included wildlife as a consideration for an alternative location analysis given the importance of avoiding impacts as the first measure to best ensure sustainable, robust wildlife populations. An alternative location analysis can provide important information for the Commission and CPW when evaluating a proposed oil and gas location. However, the Commission also recognizes that, by working with CPW, the operator could work through an analysis of avoiding impacts before submitting a proposal to the Commission for oil and gas operations. In these instances, CPW may waive the requirement for an operator to conduct the alternative location analysis.

The use of an alternative location assessment is the primary means of achieving avoidance of adverse impacts. By differentially selecting locations which by their very nature have less impact on wildlife resources, the mitigation hierarchy of avoid, minimize, then mitigate can be effectively implemented. Several stakeholders commented that a waiver from CPW would subvert the purpose and value of the alternative location analysis process. Other stakeholders commented that under this Rule, the Commission is delegating its regulatory authority by incorporating a waiver from CPW into the alternative location analysis process. Rule 304.b.(2).B.viii does not provide an avenue for operators to avoid consultation with CPW. The Rule also does not provide CPW with exclusive authority over proposed oil and gas development. Instead, a waiver from CPW acknowledges and gives credit to an operator that, prior to filing a Form 2A, has engaged with CPW in a pre-consultation discussion about identifying an appropriate location that is protective of wildlife resources within high priority habitat. The waiver under this Rule gives credit to an operator's effective planning processes when appropriate. This Rule is an example of the cooperative nature of the relationship between the Commission and CPW, which is envisioned by the habitat stewardship provisions in C.R.S. § 34-60-128.

Rule 309.e.

Rule 309.e nests within the Commission's various processes for consultation and specifies the purpose and process for consultation with CPW. An important objective of the consultation is for the Commission and operator to obtain the best available information from CPW regarding potential impacts to wildlife resources that may result from a Form 2A, oil and gas development plan, comprehensive area plan, or other matter. The nexus for CPW consultation is a potential impact to wildlife resources, which is reflected in Rules 309.e.(2).A–G. Importantly, any proposed oil and gas location or associated new access road, utility, or pipeline corridor within high priority habitat, state parks, state wildlife areas, federally designated critical habitat or an area with a known occurrence for a federal or Colorado threatened or endangered species, or conservation easements established for wildlife habitat must receive a CPW consultation. As a result of consultation, CPW may make written recommendations to the Director about how to protect wildlife resources and conditions of approval that may be necessary and reasonable under the particular circumstances. The Director may then incorporate CPW's recommended conditions of approval as part of the Director's recommendation to the Commission. Importantly, the Commission may add any additional conditions of approval that it determines are necessary and reasonable to ensure compliance with the Commission's Rules or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources when approving an oil and gas development plan, pursuant to Rule 307.b.(1).

The Commission and CPW recognize that in certain circumstances, wildlife habitat maps may lack ground truthing, or a species may have permanently changed its distribution due to land use or habitat changes that make an area mapped by CPW as wildlife habitat incompatible with future use by wildlife. For these types of circumstances, Rules 309.e.(2).D and 309.e.(3).C provide "onramps" and "offramps" to consultation with CPW in order to ensure protections to wildlife resources.

The Commission included the term "other matter" in Rule 309.e.(2).D to include consultations where the facts on the ground identify a wildlife resource that needs consideration. Here, CPW can request a consultation where appropriate. It is important to note that this "onramp" to consultation is not limited to species and habitats identified specifically in the Rules or referenced by the broader defined term of high priority habitat—there must only be a nexus to wildlife resources, as defined in the 100 Series Rules, in order for Rule 309.e.(2).D to apply. Examples that may fall under Rule 309.e.(2).D include, but are not limited to, situations in which CPW is notified of an active raptor nest site that does not appear on the most recent high priority habitat maps provided to the Commission, or where CPW is aware of a known big game migration corridor, including pinch points and stopover areas, that does not currently appear on the high priority habitat maps.

There are also circumstances in which CPW consultation may not be necessary. First, Rule 309.e.(2).G allows CPW to waive consultation at any point, based on effective and early coordination between the operator and CPW. Second, Rule 309.e.(3).C—much like its counterpart in Rule 309.e.(2).D—recognizes that while maps are static, habitats are generally dynamic. This provision provides an "offramp" to consultation if an operator can demonstrate, and CPW agrees in writing, that a particular identified habitat and species is no longer present and unlikely to return to an area, or that a proposed oil and gas location is in an area that is either primarily or completely developed for a use that makes it incompatible with wildlife habitat. An example that may fall under Rule 309.e.(3).C includes, but is not limited to, a situation in which an operator demonstrates, and CPW agrees in writing, that a bald eagle nest is no longer present at a location and unlikely to return because the tree that hosted the nest blew down. Under these facts, Rule 1202.c.(1).G would not apply to that particular oil and gas development plan, comprehensive area plan, or Form 2A application, and no variance would be required from the application of that Rule. However, the absence of one particular species or habitat does not negate the requirement for consultation if the proposed oil and gas location also falls within a habitat area for another species, nor does it negate the application of the statewide operating requirements found in Rule 1202.a for other species or habitat.

The Commission recognizes that the federal government has an important role in supporting and bolstering the state's actions to protect wildlife resources for two reasons. First, in Colorado many of the impacts to wildlife resources intersect federally-owned surface and minerals. Second, management of species listed as threatened or endangered under the federal Endangered Species Act ("ESA") and their critical habitat must involve coordination and consultation with federal partner agencies. The Commission and CPW will continue to work closely with the U.S. Department of the Interior's Bureau of Land Management ("BLM"), especially with respect to BLM's plans for development on federally-owned surface. In addition, CPW will coordinate consultations related to federally listed species and their critical habitat, or an area with a known occurrence for a federal threatened or endangered species, with the U. S. Fish and Wildlife Service ("USFWS"). Coordinating with BLM, as a federal land manager, early in the process is important to achieving complementary permitting outcomes, and therefore, consistent with prior practice, the Commission expects operators to include all permitting agencies in on-site evaluations and identify potential conflicts to both state and federal agencies for joint resolution.

The Commission's intent to continue its cooperative relationship with BLM and other federal agencies is consistent with the Commission's legal authority under federal and state law. The Supreme Court has long recognized that states are "free to enforce [their] criminal and civil laws on federal land so long as those laws do not conflict with federal law." *Cal. Coastal Comm'n v. Granite Rock Co.*, 480 U.S. 572, 579–81 (1987) (quotation omitted). There is no conflict between the Commission's ongoing exercise of its statutory authority to regulate wildlife on federal lands and federal law, in part because BLM's statutory authority to regulate oil and gas development and surface activities expressly authorizes state regulation. 30 U.S.C. §§ 187, 189; 43 U.S.C. § 1712(c)(9). In addition to general state authority to adopt environmental regulations that apply to oil and gas development on federal land, courts have also recognized broad state authority to regulate wildlife resources, including wildlife resources on federal lands. *See Utah Native Plant Society v. U.S. Forest Serv.*, 923 F.3d 860, 867–69 (10th Cir. 2019) (discussing 16 U.S.C. §§ 528, 1604(a); 43 U.S.C. §§ 1701(a)(8), 1732(b)). Accordingly, the Commission has legal authority to continue implementing its 1200 Series wildlife regulations on federal lands, working in close cooperation with BLM and other federal land management agency partners.

Consistent with the Commission's intent to maintain the ongoing productive relationship between the Commission, CPW, and federal partner agencies, the Commission adopted Rules acknowledging the role of its federal partner agencies. First, Rule 309.e.(1).F provides that during the consultation process, CPW will consider as a factor the extent to which proposed oil and gas operations are already incorporated into a federal land use planning document. This Rule codifies the existing practice of recognizing that federal land use planning, and the associated consideration of appropriate wildlife resource protections, is an important factor in the CPW consultation process. While Rule 309.e.(1).F allows CPW to consider federal land use planning documents to the extent the proposed oil and gas operations occur on federal or private lands, CPW is not precluded from requesting additional measures beyond those proposed by the federal plans. Additionally, in Rule 309.e.(4).B, the Commission specified that pre-consultation or consultation with federal land management agencies may shorten the overall timeframe for consultation with CPW. And in Rule 309.e.(5).E, the Commission explicitly recognized the extent to which recommendations from a relevant federal land management agency may be considered in circumstances where an operator seeks a variance from the application of a Rule protecting wildlife resources.

An operator may engage with CPW in a pre-consultation prior to filing its proposed location application materials, including the oil and gas development plan or Form 2A. This pre-consultation with CPW will help determine whether a proposed location may adversely impact wildlife resources, which incorporate the high priority habitats listed in Rule 1202.c.(1), and whether CPW may support a variance request. Several stakeholders raised concerns around perceived inefficiencies of the variance process as it relates to CPW consultation in Rule 309.e and the high priority habitats listed in Rule 1202.c.(1). The Commission anticipates considering variance requests as part of a Commission hearing on an operator's proposed location application materials. If an operator discloses its intent to request a variance from the application of a subsection of Rule 1202.c.(1) during pre-consultation with CPW and receives support for that variance request at that time, this information will be carried forward into the formal consultation process described by Rule 309.e and may streamline the Commission's consideration of the variance.

Importantly, the formal consultation process in Rule 309.e does not commence until an operator submits its proposed location application materials. Relatedly, CPW's ability to waive a certain provision does not become possible until the application materials for the proposed location are filed. Following the submission of an operator's proposed location application materials, the Commission's Staff and the Director can weigh CPW's recommendations—including its support for a variance—and the recommendations of federal land managers, as applicable. Using all of this information, the Commission will make a fully informed determination on a location application, consistent with its mission and statutory mandate, rather than relying on a waiver decision made by a different agency.

Following the consideration of robust stakeholder feedback, in Rule 309.e.(5).D, the Commission adopted waiver and variance requirements for the sensitive habitats found in Rule 1202.c. Recognizing the importance of landscape level planning, in Rule 309.e.(5).D.iv, the Commission adopted a provision allowing CPW to waive the provisions of Rule 1202.c for sites preliminarily approved as part of a comprehensive area plan pursuant to Rule 314. The Commission also adopted Rule 309.e.(5).C, which provides that CPW may waive, in writing, any operating or mitigation requirement otherwise required by Rules 1202 or 1203, except for Rule 1202.c habitats. In Rule 309.e.(5).D, the Commission approved a tiered waiver and exception approach to CPW consultation that would inform the application of Rules 1202.c.(1).Q–S, while maintaining a no surface occupancy standard for listed terrestrial habitats. Under this approach, the Commission maintained the variance process for operations within zero to 300 feet of the ordinary high water mark from cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and perennial segments of sportfish management waters. The Commission also adopted the variance process for operations within zero to 500 feet of CPW designated Gold Medal waters. If the Commission grants a variance request in these sensitive riparian areas, it anticipates requiring operators to adhere to best management practices comparable to or more protective than those listed in Rules 309.e.(5).D.i and ii and Rule 1202.a.(10), based on the individual circumstances.

The Commission set forth these best management practices that apply when an operator proposes a location from 300 feet to 500 feet of the ordinary high water mark from cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and perennial segments of sportfish management waters. The best management practices are listed in Rules 309.e.(5).D.i and ii, and include performance of daily inspections, unless a different inspection frequency or alternative method of compliance has been approved on the Form 2A, and maintaining adequate spill response equipment at the oil and gas location during drilling and completion operations. Pursuant to Rule 309.e.(5).D.ii.bb, these best management practices will apply to ephemeral and intermittent segments of sportfish management waters if a waiver is granted by CPW and the Director approves an exception.

The Commission's proposed revisions to Rule 309 included changes to the wildlife protection plan the Commission made to Rule 304.c.(17) in the 200–600 Series Mission Change Rulemaking. The Commission has determined the importance of a wildlife protection plan for all sites statewide to enhance protections for species not listed explicitly with high priority habitat, and to provide clarity on an operator's plans for implementation of the statewide operational requirements of Rule 1202.a.

The Commission also articulated a process to follow for consultation with CPW. Many stakeholders raised concerns about the discretion afforded to both the Director and CPW, including both the opportunity for the Director to recommend that the Commission not adhere to CPW recommendations, and for CPW to recommend denial of a permit. It is important to understand that these provisions exist in the circumstance that CPW and the Director disagree and provide for elevating that analysis to the Commission for a decision. Important statutory safeguards, including the use of the terms "reasonable and necessary" in the definition of "minimize adverse impacts," C.R.S. § 34-60-103(5.5), as well as the Administrative Procedure Act and C.R.S. § 24-4-104, always apply to actions by the Commission or CPW.

Certain stakeholders also raised concerns about whether the Commission has ceded its regulatory authority by allowing operators to seek a waiver from CPW regarding certain operating and mitigation requirements listed in Rules 1202 and 1203. However, Rule 309.e.(5) does not cede Commission's regulatory authority to CPW. Instead, it emphasizes the importance of cooperative analysis and consultation between the agencies to achieve necessary wildlife resource protection while preserving avenues to seek a Director's exception in certain circumstances. The Commission will continue to rely upon CPW to provide recommendations based on its expertise in the area of wildlife and habitat management. Ultimately, the

Commission will retain final decision-making power with respect to whether an operator has complied with its Rules following the consultation with and recommendation from CPW.

As a direct result of Senate Bill 19-181's revisions to the Act, C.R.S. § 34-60-128(3)(b), the Commission also clarified that while a surface owner can refuse to grant access to their property to facilitate onsite consultation and can refuse to allow wildlife-related conditions of approval that might affect their use of their land (*e.g.*, timing stipulations), the surface owner cannot prevent the Commission from requiring compensatory mitigation or offsite wildlife mitigation efforts as a Form 2A condition of approval. This will solidify protections in circumstances and locations when impacts to wildlife from proposed development are unavoidable and offsite compensatory mitigation may therefore be appropriate.

Rule 529.

The Commission moved prior Rule 306.c.(1).B to Rule 529.a to ensure coordination with CPW on wildlife resource-related issues during proceedings to adopt or modify field-wide or basin-wide orders. Prior Rule 306.c.(1).B described this authority in the consultation procedures for the Form 2A, but because such consultation has always occurred outside that administrative process, the Commission moved it to its appropriate context in the Commission's Rules governing basin-wide orders.

Rule 1201.

Rule 1201 creates the general framework and varying tools available for operators to plan for operations that may or will impact wildlife resources. A wildlife protection plan is specific to new or amended Form 2As for oil and gas locations outside of high priority habitat. It describes statewide operating practices and measures that will be implemented to avoid, minimize, and mitigate adverse impacts to wildlife resources. In contrast, a wildlife mitigation plan will be submitted with new or amended Form 2As within high priority habitat. The wildlife mitigation plans are agreements between an operator and CPW regarding how to avoid, minimize, and mitigate adverse impacts to wildlife resources for either a single location, or for multiple locations on a landscape scale meaningful to address habitat fragmentation and cumulative impacts to wildlife. Wildlife mitigation plans will include statewide operating requirements, along with additional operating requirements articulated in Rules 1201.b, 1202, and 1203 that apply within high priority habitat. Other conservation plans refer to plans to avoid, minimize, and mitigate adverse impacts to wildlife resources implemented through other programs that are intended to also satisfy, in whole or in part, an operator's need to address impacts to wildlife from the development activities contemplated under the Commission's Rules. The Commission designed these tools to be flexible and encourage coordination with the federal government and CPW, and landscape level planning. A description of the wildlife plans required by Rule 1201 is included in Attachment 1, the FAQ.

Some stakeholders raised concerns about whether existing wildlife plans will be honored under the Rules the Commission adopted in the 800/900/1200 Mission Change Rulemaking. The Commission acknowledges that many operators have ongoing wildlife mitigation plans. Therefore, pre-existing CPW-approved wildlife mitigation plans in effect when the new Rules take effect may meet the requirements of Rule 1201.b, subject to written concurrence from CPW. These situations will be resolved on a case-by-case basis.

Rule 1202.

In Rule 1202, the Commission updated, adapted, and added to the operating requirements and restrictions surrounding the protection of wildlife resources.

Rule 1202.a

The statewide operating requirements in Rule 1202.a are accepted by the Commission and CPW as appropriate measures to minimize impacts to wildlife resources, and will be described in the operator's wildlife protection plan. Most of the requirements listed in Rule 1202.a existed in prior Rules 1203 and 1204. Certain operating requirements, like utilizing certain seed mixes, installing wildlife escape ramps for trenches left open more than five consecutive days, and treating pits to control the potential spread of West Nile virus to wildlife, have been expanded to apply statewide in furtherance of the Commission's mandate to minimize adverse impacts to wildlife species and habitats. Other requirements, like installing and utilizing bear-proof dumpsters, applied statewide under the prior Rules.

Rule 1202.a.(4)

In Rule 1202.a.(4), and consistent with changes to Rules 603.h and 909.f, the Commission adopted a requirement governing fencing and netting pits. The Commission required that all new pits must be fenced, and either netted or covered with another wildlife exclusion method approved by CPW, within five days after the cessation of active drilling and completion activities and maintained until the pit is removed from service and dried or closed pursuant to the Commission's 900 Series Rules. The Commission also gave the Director the discretion to determine when to fence and net or install other CPW-approved exclusion devices at an existing pit on a case-by-case basis and required operators to maintain such fencing and netting or other exclusion devices.

The Commission determined that fencing and netting is an appropriate requirement to apply to all new pits and more prudent to apply to existing pits on a case-by-case basis. As explained in more detail above in the discussion of Rule 909.j, fencing and netting pits is an effective mechanism of excluding access by humans and livestock. Most importantly for the purposes of the 1200 Series Rules, fencing and netting pits is important for preventing adverse impacts to wildlife. The experience of both the

Commission and CPW, as well as evidence in the administrative record, demonstrates that wildlife mortality, especially bird mortality, is a significant and ongoing risk posed by some pits. Pursuant to Rule 1202.a, operators may, on a case-by-case basis, seek a waiver from CPW if netting or fencing a new pit is not appropriate, and may also seek a variance from the Commission pursuant to Rule 502 as part of the operators' Form 15, Earthen Pit Report/Permit application. With respect to existing pits, the Commission recognizes that the produced water sampling and analysis required by Rule 909.j will inform the decision about whether fencing or netting is appropriate for an existing pit. The decision will be based on the characteristics of the produced water in the pit, and whether those characteristics could be harmful to wildlife that ingests or otherwise comes into contact with the produced water.

Rule 1202.a.(5)

The Commission also considered whether to add language to Rule 1202.a.(5) to protect wildlife access to open pipes. However, the Commission determined that this addition was redundant of other measures in the Commission's Rules and chose not to adopt the proposed language. Specifically:

- Rule 406.e.(1) provides that operators will secure conductors and cellars to prevent accidental access by people, livestock, or wildlife when active work on that conductor is not occurring.
- Rule 406.e.(3).B directs operators to cover and fence all rat holes, mouse holes, and cellars with materials sufficient to prevent accidental access by people, livestock, or wildlife.
- Rule 608.b.(7) requires that all stacks, vents, or other openings on fired vessels, heater-treaters, and separation equipment will be equipped with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.
- Rule 903.b.(3) provides that combustors used during drilling operations will be enclosed.
- Rule 903.d.(5) directs that all flared gas will be combusted in an enclosed device.

Rule 1202.a.(7)

Rule 1202.a.(7) requires operators to use CPW-recommended fence designs when consistent with the surface owner's approval and any relevant local government requirements. A similar provision existed as part of the prior Rules. In response to stakeholder concerns, the Commission clarified that any exclusion fencing will be tailored to the species present.

Rule 1202.a.(8)

The Commission also adopted Rule 1202.a.(8), a new statewide requirement to encourage operators to conduct vegetation removal outside of nesting season for migratory birds. Following a review of the available state and federal best management practices, the Commission and CPW agreed that a timing stipulation preventing vegetation removal during the nesting season would be the most appropriate way to address concerns regarding impacts to nesting migratory birds.

Several stakeholders highlighted the importance of implementing measures protective of migratory birds, and some stakeholders questioned whether hazing is an appropriate method to employ when vegetation removal must be scheduled during nesting season. The primary mechanism to avoid impacts to nesting birds is the timing stipulation on vegetation removal. When that is not possible, most operators will choose to implement surveys for nesting migratory birds in areas proposed for disturbance. Any active nests would be marked and the operator would work with the Commission's Staff and CPW to determine the appropriate buffers to prevent nest abandonment. Removal of vegetation and habitat would not continue within that buffer until the young had fledged from the nest. The use of hazing or exclusion measures is included as an option to prevent the establishment of nests in habitat that is scheduled for imminent removal. It is anticipated this is most likely to occur at small temporal and spatial scales; it is likely to be short-term, and only involve small habitat areas. At no time should migratory birds with active nests be hazed or impacted under the provision on hazing.

Rule 1202.a.(10)

In Rule 1202.a.(10), the Commission adopted a requirement to use best management practices between 500 and 1,000 feet hydraulically upgradient from Gold Medal waters, cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters. The intent of this regulation is to avoid adverse impacts from oil and gas operations, including but not limited to controlling potential spill events, preventing infiltration of operating fluids, and sedimentation. The Commission recognized the importance of incorporating requirements to address the protection of these sensitive riparian areas and, consistent with the mitigation hierarchy, adopted measures focused on minimizing the severity of any potential impacts in these areas due to oil and gas operations.

CPW may waive the requirements listed in 1202.a, as appropriate, based on site-specific considerations with final Director or Commission approval. For site-specific surface management requirements, the Commission and CPW will work with BLM and other federal surface management agencies on federally owned or managed surface. As discussion above, pursuant to Rule 1201, site-specific measures and best management practices will be described in an operator's wildlife protection plan, which is described in more detail in Attachment 1, the FAQ.

Rule 1202.b

Similar to the statewide requirements in Rule 1202.a, Rule 1202.b articulates one additional operating requirement that applies to oil and gas operations within CPW-designated high priority habitat. Under Rule 1202.b, operators are required to bore rather than trench when crossing perennial streams identified as aquatic high priority habitat. This requirement existed in prior Rule 1203. Given the importance of these habitats, the Commission determined that an additional requirement is appropriate in order to minimize adverse impacts to wildlife species and habitat. The Commission also determined this requirement is reasonable in order to implement the mandate of Senate Bill 19-181 as it relates to High Priority Habitat. As described in Rule 1201, site-specific measures and best management practices will be described in an operator's wildlife mitigation plan for sites intersecting High Priority Habitat. The FAQ in Attachment 1 includes additional information on the wildlife mitigation plan.

Rule 1202.c

In Rule 1202.c, the Commission modified its prior restricted surface occupancy Rules to align the restrictions to the high priority habitat system, and to conform to CPW's current no surface occupancy ("NSO") recommendations for habitat and species protections. Rule 1202.c provides the best example of how the Commission has updated its Rules to reflect the mitigation hierarchy contemplated by Senate Bill 19-181 and in 1202.c.(1).Q–S, the Commission created a riparian setback. The specific habitats and management areas listed in Rule 1202.c.(1) are the most sensitive wildlife resources in the state, and avoidance of these areas as the single most protective strategy is supported by robust data in the administrative record, including evidence provided by CPW.

In Rules 1202.c.(2).A and B, exceptions requiring prior Commission approval and consultation with CPW have been provided for certain time-sensitive activities and non-emergency workovers at existing locations. Rule 1202.c.(2).C also makes an exception for certain access road and flowline/utility activities in riparian areas. CPW intends that each consultation will be performed in a timely manner so as not to unreasonably delay these activities. Consistent with changes throughout the Commission's Rules, rather than specifying that operators may seek a variance in the text of the rule, the Commission intends for operators to seek variances from the application of Rule 1202.c.(1) pursuant to Rule 502. For those species listed in Rules 1202.c.(1).Q–S, an operator would need to seek a variance from the application of those Rules. However, for Rules 1202.c.(1).R and S, an operator would seek a variance only if the operator was unable to obtain a waiver of and exception to the CPW consultation provisions, as provided for in Rule 309.e.(5).D.

The Commission acknowledges that, based on the recommendations provided by CPW, avoidance is the single most effective protection strategy for the listed high priority habitats in Rule 1202.c.(1) because impacts to these habitats are difficult or impossible to minimize or mitigate. However, some stakeholders raised questions about what type of relief is appropriate when seeking to locate operations within the sensitive high priority habitats listed in Rule 1202.c.(1). As with all of the Commission's Rules, if circumstances in an individual case require a variance from the Commission's Rules, and the variance is equally or more protective of public health, safety, welfare, the environment, and wildlife resources, an operator may seek a variance pursuant to Rule 502. The Commission believes that the variance process is appropriate for the habitats in Rule 1202.c.(1) because creating a categorical waiver and exception process within Rule 1202 is neither consistent with the mitigation hierarchy nor is it consistent with CPW's recommendations on these sensitive habitats.

Pursuant to Rule 502.c, certain requirements apply when an operator or other applicant seeks a variance from the Commission from the application of a Rule. An operator or applicant must show that it has made a good faith effort to comply, or is unable to comply with the requirements of a specific Rule provision; that the requested variance will not violate the Act's intent; the requested variance is necessary to avoid an undue hardship; granting the variance will result in no net adverse impact to public health, safety, welfare, the environment, or wildlife resources; and the requested variance contains reasonable conditions of approval or other mitigation measures to avoid, minimize, or mitigate adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Commission acknowledges that an operator's good faith effort to comply and perceived undue hardship, two required elements under Rule 502.c, may involve discrete considerations as applied when a variance is sought from the application of Rule 1202.c. For instance, an operator's good faith effort to comply with Rule 1202.c may be viewed in the context of the alternative location analysis, which is required under Rule 304.b.(2).B.viii. Here, for example, the Commission may consider whether the operator has the support of CPW for a more preferential site. The Commission could also consider re-use of an existing location when evaluating a variance request from the application of Rule 1202.c, but it is not dispositive of the analysis. Additionally, with respect to undue hardship, the Commission recognized that the analysis of this provision should not be limited to purely financial considerations and should instead involve greater considerations including, but not limited to, the inability to access minerals, whether significant construction will be required, or whether certain geographic concerns are present, as examples.

Many stakeholders suggested that the variance process is both inefficient and burdensome in the context of the four riparian areas found in Rules 1202.c.(1).Q–S. Acknowledging there may be different variables to consider in these riparian habitats, and based on the recommendations of CPW and the supporting literature in the administrative record, the Commission adopted a tiered approach to the CPW consultation that would inform the application of Rules 1202.c.(1).Q–S, which is discussed in more detail above.

As outlined below and in the additional information provided in Attachments 3 and 4, specific changes and additions to the prior Rules are based on the best available science, established wildlife management recommendations, and existing state policy.

Rule 1202.c.(1).A Columbian sharp-tailed grouse

Columbian sharp-tailed grouse ("CSTG") currently occupy less than 10% of their historic range in the United States. Northwestern Colorado contains one of three metapopulations,[8] and is an important part of the overall range for this species. Based on the literature summarized in Attachment 4, the Commission has adopted CPW's recommendation that the CSTG NSO lek site buffer distance be increased from 0.4 miles to 0.6 miles. This increase of 0.2 miles better aligns with results from recent peer-reviewed studies that have been conducted in Colorado and other states.[9] Specifically, Hoffman *et al.* (2015) recommends that the most biologically relevant NSO distance from CSTG lek sites is 2 kilometers ("km") (1.24 miles).[10] CPW suggests that NSO lek buffers between 0.8 km (0.5 miles) and 1.0 km (0.62 miles) are acceptable for CSTG if restrictions are also placed on the density of wells and infrastructure surrounding lek sites as provided in Rule 1202.d.

Rule 1202.c.(1).B Greater prairie-chicken

The greater prairie-chicken is a Tier 2 Species of Greatest Conservation Need in the 2015 SWAP.[11] The greater prairie-chicken experienced substantial declines in population distribution and abundance in the 1900s.[12] The greater prairie-chicken

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[8] Bart, Status assessment of Columbian sharp-tailed grouse, Unpublished report to the U.S. Fish and Wildlife Service, Status Review Team (2000).

[9] Hoffman & Thomas, Columbian Sharp-tailed grouse *(Tympanuchus phasianellus columbianus)*: a technical conservation assessment, USDA Forest Service, Rocky Mountain Region (2007).

[10] Hoffman, *et al.*, Guidelines for the management of Columbian sharp-tailed grouse populations and their habitats, Sage and Columbian Sharp-tailed Grouse Technical Committee, Western Association of Fish and Wildlife Agencies (2015).

[11] CPW, State Wildlife Action Plan (2015), *available at* https://cpw.state.co.us/Documents/WildlifeSpecies/SWAP/CO_SWAP_FULLVERSION.pdf.

[12] Svedarsky, *et al.*, *Status and management of the greater prairie-chicken* Tympanuchus cupido pinnatus *in North America*, Wildlife Biology (2000).

once inhabited most of the northeastern plains in Colorado, but the population dramatically declined in the early and middle part of the 20th century. In 1973, the species was officially state-listed as endangered. With intensive management and successful transplant efforts, the greater prairie-chicken population steadily increased. Through cooperative habitat projects with eastern Colorado private landowners and local governments (*e.g.,* Yuma County and the Town of Wray), Colorado's greater prairie-chicken population rebounded, and the species was down-listed to state threatened in 1993. In 1998, CPW delisted the greater prairie-chicken to a special concern/nongame status.

Based on the literature summarized in Attachment 4, there is strong site fidelity in males with approximately 75% of the lek locations used in consecutive years.[13] Research in northeast Colorado documented that females nest within an average of 0.6 miles (1.0 km) from the closest lek.[14] Therefore, to continue to sustain and grow the population of this species in Colorado, the Commission has adopted CPW's recommendation of incorporating an NSO lek site buffer distance of 0.6 miles (1 km) for greater prairie-chickens.

Rules 1202.c.(1).C & D Greater sage-grouse and Gunnison sage-grouse

Based on the literature summarized in Attachment 4, the Commission has adopted CPW's recommendation to increase both the greater sage-grouse ("GrSG") and Gunnison sage-grouse ("GuSG") lek site buffer distance restricting construction of new oil and gas locations from 0.6 miles to 1.0 miles. This change is in closer alignment with recently published peer-reviewed literature.[15] Several recent studies conducted in Wyoming and Montana have demonstrated reductions in male greater sage-grouse attendance at distances greater than one mile to the nearest oil and gas facility.[16] Additionally, this measure is consistent with the BLM's Northwest

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[13] Schroeder & Braun, *Greater prairie-chicken attendance at leks and stability of leks in Colorado*, 104 The Wilson Bulletin 273 (June 1992); Schroeder, *Movement and lek visitation by female greater prairie-chickens in relation to predictions of Bradbury's female preference hypothesis of lek evolution*, The Auk (1991).

[14] Schroeder, *supra* note 13.

[15] Manier, *et al.*, Conservation Buffer Distance Estimates for Greater Sage-Grouse—A Review, U.S. Geological Survey Open-File Report 2014-1239 (2014).

[16] Naugle, *et al.*, *Sage-grouse and cumulative impacts of energy development*, *in* Cumulative Effects of Wildlife Management (Krausman and Harris, eds., 2011); Johnson, *et al.*, *Influences of environmental and anthropogenic features on Greater Sage-Grouse populations, 1997-2007*, *in* 38 Greater Sage-Grouse: Ecology and Conservation of a Landscape Species and its Habitats: Studies in Avian Biology (Knick and Connelly eds., 2011); Holloran, *et al.*, *Yearling greater sage-grouse*

Colorado 2015 and 2019 Greater Sage-grouse Approved Resource Management Plans that contain a 1.0 mile lek buffer distance resulting in no new leasing (2015) or strict NSO stipulations (2019).

There is not a large body of oil and gas development literature specific to Gunnison sage grouse. In these instances, it is appropriate to utilize the existing information published in the scientific literature for greater sage grouse as a surrogate.[17] Due to the related behavioral and distribution responses documented in the research summarized in Attachment 4 for GrSG, a 1.0 mile buffer from a Gunnison sage grouse lek is consistent and appropriate, and sufficiently protective considering Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a). GUSG is a federally listed threatened species, and is also subject to federal regulatory requirements under the federal ESA. The USFWS Recovery Implementation Strategy ("RIS") for GuSG identifies a specific goals for conserving and protecting existing and suitable habitat near leks. To accomplish this goal RIS identifies the Commission as an activity partner who should revisit and consider modification to the existing 0.6 mile buffer for oil and gas development in Colorado.[18] The expanded buffer helps to achieve this USFWS priority conservation action identified in the RIS.

<u>Rule 1202.c.(1).E Lesser prairie-chicken</u>

The lesser prairie-chicken is a Tier 1 species in Colorado's 2015 SWAP and is identified as a Colorado state threatened species. The species has been repeatedly petitioned for listing under the federal ESA and is currently under review for federal listing under the ESA. A 12-Month Finding from the USFWS is expected May 2021. CPW is actively engaged in lesser prairie-chicken conservation through population management, habitat enhancement and restoration efforts with private landowners, and through implementation of the Western Association of Fish and Wildlife Agencies ("WAFWA") Lesser Prairie-Chicken Range-wide Conservation Plan ("RWP").[19] The State of Colorado is a member of the Lesser Prairie Chicken Interstate Working Group and a partner in the WAFWA Lesser Prairie-Chicken RWP. The RWP was

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response to energy development in Wyoming, 74 J. Wildlife Mgmt. 65 (2010); Walker *et al.*, *Greater sage-grouse population response to energy development and habitat loss*, 71 J. Wildlife Mgmt. 2,644 (2007).

[17] U.S. Fish and Wildlife Service, Species status assessment report for Gunnison sage grouse (Centrocercus minimus) (Apr. 20, 2019).

[18] United States Fish and Wildlife Service, Recovery Implementation Strategy, Version 1.0 Draft (2020).

[19] Van Pelt, *et al.*, The Lesser Prairie-Chicken Range-wide Conservation Plan, Western Association of Fish and Wildlife Agencies (2013).

developed by the five lesser prairie-chicken states (Colorado, Kansas, New Mexico, Oklahoma, and Texas), along with oil and gas and electric utility companies, private landowners, and the USFWS, as a comprehensive adaptive plan designed to conserve lesser prairie-chickens across the range.

The Conservation Strategy outlined in the RWP has two main objectives: 1) concentrate limited resources for species conservation in the most important areas, allowing for the restoration, enhancement, and maintenance of large blocks of habitat needed by lesser prairie-chickens; and 2) identify areas where development should be avoided, which also helps identify areas where development is of less concern for these birds. RWP avoidance measures include lek surveys in project areas to identify leks, and avoidance of habitat loss or fragmentation within focal areas, connectivity zones, and within 1.25 miles of leks. Based on this information and the literature summarized in Appendix 4, the Commission has adopted CPW's recommendation that the Lesser prairie-chicken NSO lek site buffer distance be increased from 0.6 miles to 1.25 miles. This increase better aligns with the current recommendations of the RWP and with results from peer-reviewed studies that have been conducted in Colorado and other states.

Female lesser prairie-chickens typically nest within 2 miles of leks.[20] Therefore, locations of leks can be indicators of where existing nesting habitat is located and indicate key areas for protecting nesting habitat. Distance from oil or gas wells was the most influential anthropogenic feature affecting lek occurrence in a study in Kansas.[21] Lek density has been positively associated with increases in total percentage of grassland and shrub-land and negatively associated with active oil and gas well density.[22] Additionally, lek abandonment was higher in areas with more roads and active wells.[23] Nesting females favor areas with large, unfragmented sand

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[20] Haukos, *et al.*, *Lesser prairie-chickens of the sand sagebrush prairie*, *in* 48 Ecology and Conservation of Lesser Prairie-Chickens, Studies in Avian Biology (Haukos and Boal, eds., 2016); Pitman, *et al.*, *Nesting ecology of lesser prairie-chickens in sand sagebrush prairie of southwestern Kansas*, 118 Wilson J. of Ornithology 23 (2006); Giesen, *Movements and nesting habitat of lesser prairie-chicken hens in Colorado*, 39 The Sw. Naturalist 96 (1994).

[21] Jarnevich & Laubhan, *Balancing energy development and conservation: a method utilizing species distribution models*, 47 Envt'l Mgmt. 926 (2011).

[22] Hagen, *Impacts of energy development on prairie grouse ecology: a research synthesis*, 75 Transactions of the North American Wildlife and Natural Resources Conference 96 (2010).

[23] Hunt, *Investigation into the decline of populations of the lesser prairie-chicken* (Tympanuchus pallidicinctus) *in southeastern New Mexico* (2004) (Dissertation, Auburn University).

sagebrush and grassland,[24] and have been shown to avoid roads, wells, and power lines.[25]

Rules 1202.c.(1).M and N Least tern and piping plover

The Commission has adopted CPW's recommendation that CPW-mapped least tern and piping plover production areas be protected with an NSO buffer. Least terns and piping plover production areas are limited to the shorelines and islands at several southeastern Colorado waterbodies.

The interior least tern (*Sterna (*now *Sternula) antillarum*) is currently listed as federal endangered under the ESA and state endangered under Colorado statutes. The species was placed on the federal Endangered Species List on June 27, 1985, 50 Fed. Reg. 21,784 (May 28, 1985), and a federal recovery plan was issued in September 1990. In October 2019, the interior least tern was proposed for delisting under the ESA. 84 Fed. Reg. 56,977 (Oct. 24, 2019). If that decision is finalized, the interior least tern will no longer be federally listed as either a threatened or endangered species; however, a post-delisting monitoring plan will be put in place.

The piping plover (*Charadrius melodus*) is currently listed as a federal threatened species under the ESA and state threatened under Colorado statutes. The Northern Great Plains population of piping plovers was listed as a federal threatened species, effective January 10, 1986. 50 Fed. Reg. 50,726 (Dec. 11, 1985). A federal recovery plan was completed in 1988 and revised in 2015. Habitat protection, management, restoration, and creation is listed as a priority action in the 2015 Recovery Plan.

CPW developed a Piping Plover and Interior Least Tern Recovery Plan in 1994 to address management needs and activities necessary to protect and enhance breeding populations, and to assist with the national recovery.[26] The *Endangered Species*

[24] Pitman, *et al.*, *Location and success of lesser prairie-chicken nests in relation to vegetation and human disturbance*, 69 J. Wildlife Mgmt. 1,259 (2005).

[25] Sullins, *et al.*, *Strategic conservation for lesser prairie-chickens among landscapes of varying anthropogenic influence*, 238 Biological Conservation (2019); Plumb, *et al.*, *Lesser prairie-chicken space use in relation to anthropogenic structures*, 83 J. Wildlife Mgmt. 1,216 (2019); Timmer, *et al.*, *Spatially explicit modeling of lesser prairie-chicken lek density in Texas*, 78 J. Wildlife Mgmt. 142 (2014); Pitman, *supra* note 24; Robel, *et al.*, *Effect of energy development and human activity on the use of sand sagebrush habitat by lesser prairie-chickens in southwestern Kansas*, 69 Transactions of the North American Wildlife and Natural Resource Conference 251 (2004).

[26] CPW, Piping plover (*Charadrius melodus*) and Interior least tern (*Sterna antillarum*) Recovery Plan (1994).

Management Plan for Piping Plovers (Charadrius melodus) and Interior Least Tern (Sterna antillarum athalassos) was developed by the U.S. Army Corps of Engineers for John Martin Reservoir in 2002. CPW works annually with the U.S. Army Corps of Engineers and the USGS at John Martin Reservoir and at other waterbodies in southeastern Colorado regarding management of these production areas. The protection of essential habitat and the goal to protect, enhance, and increase breeding populations is a key component of both the federal and state recovery plans. Given the limited habitat available for nesting in these areas, protection of production areas with NSO is necessary to avoid adverse impacts to breeding populations of least terns and piping plover in Colorado.

Rule 1202.c.(1).O Townsend's big-eared bat, Mexican free-tailed bat, and myotis

The Commission has adopted CPW's recommendation to protect hibernacula/winter roost sites for Townsend's big-eared bat, Brazilian free-tailed bat, or *Myotis* species with a 350-foot NSO buffer due to the sensitivity of these sites to disturbance and their importance for the conservation of these species.

Townsend's big-eared bat (*Corynorhinus townsendii*) and fringed myotis (*Myotis thysanodes*) are Colorado listed Species of Special Concern, and Tier 1 Species of Greatest Conservation Need (SGCN) in Colorado's SWAP. In addition, the spotted bat (*Euderma maculatum*) and the little brown bat (*Myotis lucifugus*) are Tier 1 species and the big free-tailed bat (*Nyctiomops macrotis*) and the hoary bat (*Lasiurus cinereus*) are Tier 2 species. The species composition of roost sites can be composed of several different bat species with the genus *Myotis*. Thus, it is more useful to protect the hibernacula/roost site for genus Myotis rather than individual species of *Myotis*.

There is evidence to suggest that roosting habitat is a limiting factor for many bat species.[27] All species found in Colorado need adequate summer and winter sites, with appropriate microclimatic conditions to raise their young and hibernate (for non-migratory species) during winter. Many species utilize a variety of roosting habitats, including caves, mines, trees, rock crevices, talus slopes, and anthropogenic structures. Some species are much more limited to certain roost habitat types. Roost disturbance can be an issue at both summer and winter sites. Disturbances that cause hibernating bats to arouse, or wake up, during the hibernation time period can cause bats to burn vital fat reserves, which can lead to the starvation of the bat prior to the end of the winter season.[28] Oil and gas operations may directly impact bats

[27] McCracken, *Who's endangered and what can we do?*, 6 Bats 5 (1988); Humphrey & Kunz, *Ecology of a Pleistocene relict, the western big-eared bat (Plecotus townsendii), in the southern Great Plains*, 57 J. Mammalogy 470 (1998).

[28] 2 Colorado Bat Conservation Plan (Navo, *et al.*, eds., Colorado Committee of the Western Bat Working Group 2018).

through sensory disturbance of noise and light associated with drilling and production.[29] Surface disturbance can transmit to underground locations from both direct and indirect means. The transfer of sound through rock to the roost site may be at high levels if surface activity is close to roost sites. Additionally, if such activity is very close, the surface disturbance may cause the collapse of internal passages. Disturbance can cause bats to abandon important roost sites. For these reasons, the protection of roost sites is supported not only by CPW, but also by the Western Association of Fish and Wildlife Agencies, the Western Bat Working Group, and the Colorado Bat Working Group. Avoiding disturbance of these roosting habitats is critical to preventing the potential decline in bat populations.[30]

The 2018 Colorado Bat Conservation Plan summarizes several buffer distances that have been recommended to protect bat roosts and hibernacula. Those reported values range from 2 miles for pesticide spraying to 100 feet for tree harvesting. The buffer zones should reflect the species composition and sensitivity of roost sites and its biological importance for maintaining local bat populations.[31] CPW recommends a minimum surface disturbance buffer of 350 feet from the hibernacula/roost year-round to protect the site integrity for bat use. This recommendation corresponds to one established by the BLM in 1995 which prohibits "new surface disturbing activities within a 350 foot radius of a cave opening or any known cave passages which may adversely impact any significant or potentially significant cave resource value." 60 Fed. Reg. 19,078 (Apr. 14, 1995).

Rule 1202.c.(1).Q Waters identified by CPW as "Gold Medal"

The Commission included waters identified by CPW as "Gold Medal" in Rule 1202.c.(1) based on the recommendations of CPW's aquatic professionals regarding potential development impacts to these waterways. The Commission adopted a 500-foot NSO to protect this habitat and, therefore, an operator is required to request a variance in order to locate any ground disturbance within zero to 500 feet of the ordinary high water mark of CPW-identified Gold Medal waters. Gold medal waters represent exceptional angling opportunities for the roughly 1.4 million anglers who sportfish in Colorado, annually. These anglers provide funding for conservation efforts and contribute greatly to Colorado's economy. Gold medal waters are subject to meeting rigorous criteria, over many years, to earn this designation. Gold medal

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[29] *Id.*

[30] Pierson, *et al.*, Species Conservation Assessment and Strategy for Townsend's Big-Eared Bat (*Corynorhinus townsendii townsendii* and *Corynorhinus townsendii pallescens*), Idaho Conservation Effort, Idaho Department of Fish and Game (1999).

[31] Neubaum, *et al.*, *Guidelines for defining biologically important bat roosts: a case study from Colorado*, 8 J. Fish & Wildlife Mgmt. 272 (2017).

waters must hold at least 60 pounds of trout per acre and contain an average of at least 12 trout over 14-inches or longer in length per acre. Therefore, if the Commission grants a variance request from the application of Rule 1202.c.(1).Q, it anticipates requiring operators to adhere to best management practices comparable to or more protective than those listed in Rules 309.e.(5).D.i and ii and Rule 1202.a.(10), based on the individual circumstances.

Rules 1202.c.(1).R and S Cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters

The Commission included cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters in Rule 1202.c.(1) based on the recommendations of CPW's aquatic professionals regarding potential development impacts to these waterways. The Commission adopted tiered aquatic setbacks based on evidence in the administrative record, the expert recommendations of CPW, and input from stakeholders. These tiered setbacks represent the Commission's understanding of science coupled with the direction from Senate Bill 19-181 to increase protections for wildlife resources. Much of the rationale for this change is described below and in the references provided in Attachments 3 and 4.

The Commission adopted a 500-foot NSO for Rule 1202.c.(1).R, cutthroat trout crucial habitat, and native fish and other native aquatic species conservation waters. CPW can waive this NSO, with Director support, if an operator proposes to locate operations within 300 to 500 feet of any Rule 1202.c.(1).R stream segment. Mandatory best management practices will apply from 300 to 500 feet, as described Rule 309.e.(5).D.i, and an operator must seek a variance from the Commission in order to be granted relief within zero to 300 feet of any Rule 1202.c.(1).R stream segments. If the Commission grants a variance request from the application of Rule 1202.c.(1).R, it anticipates requiring operators to adhere to best management practices comparable to or more protective than those listed in Rules 309.e.(5).D.i and ii and Rule 1202.a.(10), based on the individual circumstances.

The Commission adopted a 500-foot NSO for Rule 1202.c.(1).S, sportfish management waters. CPW can waive this NSO, with Director support, if an operator proposes to locate operations within 300 to 500 feet of any perennial Rule 1202.c.(1).S stream segment, and mandatory best management practices will apply, as described in Rule 309.e.(5).D.ii.aa. A variance process is required for locating within zero to 300 feet of a Rule 1202.c.(1).S perennial stream segment. Again, if the Commission grants a variance request from the application of Rule 1202.c.(1).S to a perennial sportfish management water stream segment, it anticipates requiring operators to adhere to best management practices comparable to or more protective than those listed in Rules 309.e.(5).D.i and ii and Rule 1202.a.(10), based on the individual circumstances. Given the difficulty of evaluating intermittent and ephemeral stream segments off mapped data alone, CPW can waive locations within zero to 300 feet of Rule 1202.c.(1).S intermittent and ephemeral stream segments, with Director support and after consulting with the operator, and the mandatory best management practices listed in Rule 309.e.(5).D.ii.bb will apply.

Minimum buffers recommended in literature for Gold Medal and sportfish management waters vary and reach up to 950 feet (*see* Table 1200-1 below). The Commission concluded that tiered protections, up to 500 feet, are reasonable to protect these aquatic resources given the protective directive of SB 19-181. The precedence for 300 to 500-feet riparian setbacks is set in many existing land management documents (*see* Table 1200-2 below). For example, the Record of Decision ("ROD") for Interim Strategies for Managing Anadromous Fish-producing Watersheds in Eastern Oregon and Washington, Idaho and Portions of California provides a 300-foot Riparian Habitat Conservation Areas on either side of fish-bearing streams.[32] In addition, the White River National Forest Oil and Gas Leasing Final Environmental Impact Statement Record of Decision provides NSO stipulations for Gold Medal fisheries to protect water quality and the recreational opportunities provided by the fisheries.[33] The ROD also provides NSO stipulations (at least 350 feet either side of the stream) for Colorado River cutthroat trout waters.

Native fish and other native aquatic species conservation waters are primarily composed of CPW SWAP Tier 1 and Tier II fishes and boreal toads. The above citations that support sportfish management waters also support a 500-foot recommendation for SWAP Tier I and Tier II fishes. The 2001 Boreal Toad Conservation Plan and Agreement, prepared by the Boreal Toad Recovery Team and Technical Advisory group (comprised of USFWS, U.S. Forest Service ("USFS"), BLM, USGS, National Park Service, EPA, CPW, Wyoming Game & Fish Department, New Mexico Department of Game & Fish, and Colorado Natural Heritage Program conservation professionals) recommends at least a 300-foot buffer around known or suitable toad habitat.[34]

Multiple scientific publications stress the importance of ephemeral and intermittent

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[32] U. S. Forest Service and BLM, Decision Notice/Decision Record, Environmental Assessment for the Interim Strategies for Managing Anadromous Fish-Producing Watersheds in Eastern Oregon and Washington, Idaho, and Portions of California (1995).

[33] U.S. Forest Service, White River National Forest Oil and Gas Leasing Final Environmental Impact Statement Record of Decision, White River National Forest, Supervisor's Office (1993).

[34] Boreal Toad Recovery Team and Tech. Advisory Group, Conservation Plan and Agreement: For the Management and Recovery of the Southern Rocky Mountain Population of the Boreal Toad (*Bufo Boreas Boreas*) (Loeffler, ed. 2001).

streams to native and sportfish species.[35] The use of these habitat types is oftentimes short in duration and seasonal, but critical to the life history of many species with respect to spawning, rearing, refuge, foraging, and dispersion. These stream types can be completely devoid of water for most of the calendar year, but heavily used for the short period of time in which water is present. During droughts, these streams may be dry for one or more consecutive years. A primary example of this is Cottonwood Creek, a tributary in the Gunnison River Basin, which is dry for much of the year (Figure 1) but supports large amounts of native species spawning when seasonal flows are present (Figure 2).[36]

Not all intermittent and ephemeral streams in Colorado are included in the native fish and other native aquatic species conservation waters, and sportfish management waters layers. Only intermittent and ephemeral streams that are relevant to native fish and other native aquatic species conservation waters and sportfish management waters are included. Recognizing some flexibility may be appropriate on a case-by-case basis, the Commission has also authorized CPW to waive and the Director to allow an exception for intermittent and ephemeral streams within native fish and other native aquatic species conservation waters, and sportfish management waters.

Of all the USGS-mapped National Hydrography Dataset ("NHD") features in Colorado, only 22.4% of streams and 65.5% of larger water bodies in the state are categorized by CPW for fisheries management. Approximately 10.2% of NHD streams are identified as sportfish management waters and 6.1% of NHD streams are identified as native fish and other aquatic species streams. These two management categories often include tributaries that support downstream habitats through the provision of a number of services, some of which are detailed above. These layers were developed by aquatic biologists for fisheries management purposes,

[35] Colvin, *et al.*, *Headwater Streams & Wetlands are Critical for Sustaining Fish, Fisheries, & Ecosystem Services*, 44 Fisheries 73 (2019); Heim, *et al.*, *A general model of temporary aquatic habitat use: Water phenology as a life history filter*, 20 Fish & Fisheries 802 (2019); Hooley-Underwood, *et al.*, *An Intermittent Stream Supports Extensive Spawning of Large-River Native Fishes*, 148 Transactions of the Am. Fisheries Soc'y 426 (2019); Bestgen, *et al.*, *A Dynamic Flow Regime Supports an Intact Great Plains Stream Fish Assemblage*, 146 Transactions of the Am. Fisheries Soc'y 903 (2017); Fausch & Bramblett, *Disturbance and Fish Communities in Intermittent Tributaries of a Western Great Plains River*, 1991 Copeia 659 (1991); Erman & Hawthorne, *The Quantitative Importance of an Intermittent Stream in the Spawning of Rainbow Trout*, 105 Transactions of the Am. Fisheries Soc'y 675 (1976); Erman & Leidy, *Downstream Movement of Rainbow Trout Fry in a Tributary Sagehen Creek, Under Permanent and Intermittent Flow*, 104 Transactions of the Am. Fisheries Soc'y 467 (1975).

[36] Hooley-Underwood, *et al.*, *supra* note 35.

but their origins do not preclude use in other efforts.

Figure 1. Cottonwood Creek, a tributary in the Gunnison River Basin, March 28, 2019.

Figure 2. Cottonwood Creek, a tributary of the Gunnison River Basin, May 29, 2019.

Table 1200-1. Aquatic Buffer Best Management Practices Precedents

Agency	Buffer Distance	Type	Applies To	Details	Location	Reference
BLM	0.5-mile	Stream Buffer	Native Trout, Blue & Red Ribbon Fisheries	Blue & Red Ribbon Fisheries are the equivalent of Gold Medal Waters. This RMP provided opportunities for oil and gas development.	Lewistown, Montana	2020 Lewistown Field Office Resource Management Plan
BLM	0.5-mile	Stream Buffer	Native Trout, Blue Ribbon Fisheries	Applies to Blue Ribbon Fisheries, which are the equivalent of Gold Medal Waters.	Billings, Montana	Billings Field Office Greater Sage-Grouse Approved Resource Management Plan, Appendix S
BLM	0.25-mile	NSO	Colorado River cutthroat trout conservation populations and streams	0.25-mile (1,320 foot) NSO buffer to conserve Colorado River cutthroat trout.	Tres Rios Field Office, Colorado	Tres Rios Field Office Resource Management Plan, Appendix H
BLM	328 feet	NSO	Streams/Springs Possessing Lotic Riparian Characteristics	Prohibit surface occupancy and surface-disturbing activities within a minimum distance of 100 meters (328 feet) from the edge of the ordinary high-water mark (bankfull-stage).	Grand Junction Field Office, Colorado	Grand Junction Field Office, Resource Management Plan, Allowable Use W-AU8, Stipulation NSO-2

BLM	0.25-mile	NSO	Perennial Water	NSO for up to 0.25-mile from perennial water sources, if necessary, depending on type and use of the water source, soil type, and slope steepness.	Little Snake Field Office, Colorado	Little Snake Field Office, Resource Management Plan, Perennial Water LS-105 No Surface Occupancy Stipulation
USFS	350 feet	NSO	Fisheries	NSO for Gold Medal Fisheries and the recreational opportunities provided by the fisheries.	White River National Forest, Colorado	White River National Forest, Oil & Gas Leasing Final Environmental Impact Statement, Record of Decision 1993
BLM	0.5-mile	Stream Buffer	Native trout and Blue Ribbon Fisheries	Applies to Blue Ribbon Fisheries, the equivalent of Gold Medal Waters.	Dillon, Montana	2006 Dillon Field Office Resource Management Plan, Appendix K

Table 1200-2. Riparian Buffer Distances Shown in Literature

Aquatic Buffers Relevant To:	Distance (Feet ("ft."))	Citation
Amphibians	≥ 200 ft.[2]	Boyd, L. 2001. Buffer zones and beyond: Wildlife use of wetland buffer zones and their protection under the Massachusetts Wetland Protection Act. Project report to the Department of Natural Resources Conservation, University of Massachusetts. 33 pp.
Amphibians	384–673 ft.	Sheldon, D., T. Hruby, P. Johnson, K. Harper, A. McMillan, T. Granger, S. Stanley, and E. Stockdale. 2005. Wetlands in Washington State - Volume 1: A Synthesis of the Science. Washington State Department of Ecology, Olympia, WA. 85 pp.
Amphibians	390–1,900 ft.	Granger, T., T. Hruby, A. McMillan, D. Peters, J. Rubey, D. Sheldon, S. Stanley, and E. Stockdale. 2005. Wetlands in Washington state - volume 2: guidance for protecting and managing wetlands. Washington State Department of Ecology. Publication #05-06-008. Olympia, WA. 398 pp.
Boreal Toads	300 ft.	United States Department of Agriculture and United States Forest Service. 2002. White River National Forest Land and Resource Management Plan. White River National Forest, Supervisor's Office. Glenwood Springs, Colorado. 201 pp.
Fish	≥ 100 ft.	Granger, T., T. Hruby, A. McMillan, D. Peters, J. Rubey, D. Sheldon, S. Stanley, and E. Stockdale. 2005. Wetlands in Washington state - volume 2: guidance for protecting and managing wetlands. Washington State Department of Ecology. Publication #05-06-008. Olympia, WA. 398 pp.
General	100–300 ft.	Chase, V. P, L. S. Deming, and F. Latawiec. 1995. Buffers for wetlands and surface waters: a guidebook for New Hampshire municipalities. Audubon Society of New Hampshire. 80 pp.
General	100–750 ft.	Calhoun, A.J.K. and M.W. Klemens. 2002. Best development practices: conserving pool-breeding amphibians in residential and commercial developments in the northeast United States. MCA Technical Paper No. 5. Metropolitan Conservation Alliance, Wildlife Conservation Society. Bronx, NY. 57 pp.
General	10–840 ft.	Vermont Agency of Natural Resources. 2005. Riparian buffers and corridors: technical papers. Waterbury, VT. 39 pp.

General	100–950 ft.	Environmental Law Institute. 2008. Planner's guide to wetland buffers for local governments. 25 pp.
General	≥ 300 ft.	Bennett, K., ed. 2010. Good forestry in the granite state: recommended voluntary forest management practices for New Hampshire. 2nd ed. UNH Cooperative Extension, Durham, NH. 224 pp.
General	100–750 ft.	U.S. Army Corps of Engineers. 2015. Vernal pool best management practices (BMPs). New England District. 5 pp.

The Commission remains committed to working with CPW and stakeholders to evaluate the best strategies for maintaining protections to riparian areas, as they are some of the most sensitive areas in the state of Colorado. Therefore, the Commission instructs its Staff to promptly convene a technical working group. The Commission intends for the working group to study the riverscape concept in an effort to tailor riparian protections based on stream characteristics. The working group should include both the Commission's Staff and CPW. The Commission suggests the following framework for the working group:

- The Commission's Staff and CPW will review and prepare options to tailor aquatic and riparian protections based on stream characteristics. These options may include recommendations for NSOs, best management practices, or CPW consultation criteria, and will include an anticipated workload estimate for conducting the review.
- The draft options will be released for stakeholder input.
- The Commission's Staff will finalize its analysis of the presented options by considering stakeholder input and present findings to the Commission.
- The Commission may use the information to provide further direction to Staff.

Rule 1202.c.(1).T State Wildlife Areas and State Parks

The Commission has adopted CPW's recommendation of NSO protection for State Wildlife Areas ("SWA") to protect the quality of habitat and wildlife within SWAs, to protect the wildlife recreation experiences intended for the SWAs, and to maintain sufficient unfragmented habitat to meet CPW's management objectives for game and nongame species.

CPW policy states that SWAs are to be acquired and managed for the preservation and conservation of wildlife and their habitat, wildlife recreation experiences and other activities that are incidental to or compatible with this purpose.[37] Many of these properties were purchased with federal aid grants and any authorized uses that are incompatible with the preservation and conservation of wildlife habitat and wildlife related recreational activities are considered a diversion of federal aid funds and thus are prohibited.

CPW has made significant public investments in purchasing and acquiring SWA properties for critical habitat protection as well as providing opportunities for dispersed recreation for hunting, fishing, and wildlife viewing. Research suggests oil and gas development alters wildlife behavior and displaces wildlife.[38] Based on the most recent information available, CPW is unlikely to be able to meet its wildlife management objectives at these properties if the surface of SWAs are developed for oil and gas.

In addition, some SWAs were acquired by CPW as compensatory mitigation under the National Environmental Policy Act ("NEPA") specifically to offset other development impacts. Subsequent land use changes such as oil and gas development that negate the intent, purpose, and values of these mitigation properties would violate the underlying mitigation obligations in the supporting NEPA documents for the associated approved development projects.

No surface occupancy at SWAs is also necessary to protect the landscape context supporting wildlife-related recreation at these properties. Sportsmen and the general public have an explicit expectation that SWAs provide undeveloped habitat for wildlife and wildlife-related recreation opportunities. CPW Rule 900.C.3, 2 C.C.R. § 406-9:900.C.3, prohibits oil, gas, or mineral exploration within SWAs. Oil and gas development conflicts with the mission and experience that SWAs are expected to specifically provide wildlife-related values, including but not limited to wildlife habitat, hunting opportunities, wildlife viewing, and fishing.

The Commission has also adopted CPW's recommendation of NSO protection for State Parks in order to protect and preserve the quality of habitat and to maintain the management objectives, recreation experiences, and opportunities intended for State Parks. Pursuant to C.R.S § 33-10-101, outdoor recreation areas of Colorado are protected, preserved, enhanced, and managed for the use, benefit, and enjoyment of the public. Oil and gas development on State Parks is an incompatible use for these intended purposes.

CPW has made significant public investments in purchasing and acquiring State

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[37] CPW, Colorado Wildlife Commission Policy - Use of State Wildlife Areas (Oct. 11, 2007).

[38] Hebblewhite, A literature review of the effects of energy development on ungulates: implications for central and eastern Montana (2008).

Park properties in order to provide opportunities for dispersed outdoor recreation such as hunting, fishing, wildlife viewing, camping, hiking, and water-based sports, as well as for critical habitat protection. Based on the most recent information available, CPW is unlikely to be able to meet its management objectives for State Parks if they are extensively developed for oil and gas. Oil and gas development conflicts with the mission and outdoor recreational experiences that State Parks provide. In 2017, outdoor recreation contributed an estimated $62.5 billion in economic output, $35.0 billion in gross domestic product ("GDP") (10% of the entire state GDP), $9.4 billion in local, state, and federal tax revenue, and 511,000 jobs in the state (18.7% of the labor force)—a majority outside of the Metro Denver area.[39] SWAs and State Parks properties are critical for maintaining this sector of the state's economy.

Rule 1202.d

The subset of habitats listed in Rule 1202.d, while sensitive, are frequently managed by land managers and state wildlife agencies using impact minimization strategies, like co-locating facilities and limiting the density of surface facilities, or implementing surface disturbance caps. Evidence in the administrative record demonstrates that when properly regulated, development can occur within these areas in a manner protective of wildlife populations and their habitat. Compensatory mitigation is often utilized to offset unavoidable adverse impacts that occur in these habitats when impact minimization strategies are not successful. Consistent with Senate Bill 19-181's revision to the habitat stewardship provisions and specifically to C.R.S. § 34-60-128(3)(b), the Commission has formally adopted compensatory mitigation in Rule 1203 as part of its overall strategy to reduce habitat disturbance that results from oil and gas development. Mitigation was previously included as an option to minimize adverse impacts to wildlife species and habitats under prior Rule 1202.a. In response to stakeholder comment, the Commission reiterates that the obligation to mitigate unavoidable adverse impacts occurs only after operators seek to first avoid and then minimize impacts from oil and gas operations. C.R.S. § 34-60-103(5.5).

To properly regulate development that is protective of wildlife resources, Rule 1202.d requires preparation of a wildlife mitigation plan. The wildlife mitigation plan must include site-specific measures to address unavoidable adverse indirect impacts to wildlife that occur in these habitats when the development density exceeds one oil and gas location per square mile. This approach is supported by the best available science, established wildlife management recommendations, and state policies

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[39] CPW, The 2019 Statewide Comprehensive Outdoor Recreation Plan Executive Summary (2019), *available at* https://cpw.state.co.us/Documents/Trails/SCORP/Final-Plan/2019-SCORP-Report.pdf.

outlined below and described in more detail in Attachment 4.

Rule 1202.d.(1)–(4) Bighorn sheep, elk, mule deer and pronghorn habitats

Crucial winter habitats and migration corridors are known to be a limiting factor on big game populations in western Colorado and other high mountain areas of the western United States.[40] Increased residential and energy development in these habitats have been correlated with population decline and reduced winter fawn recruitment for some big game species.[41] Based on well-documented displacement distances and avoidance of active well pads and roads, unavoidable adverse impacts to western big game species increase in sage-dominated basin and range winter and migratory habitats when well pad densities exceed one well pad per square mile (corresponding with a road density of approximately one mile of road per square mile).[42] CPW researchers have documented that under the right circumstances, mule deer in the Piceance Basin may be able to tolerate slightly higher levels of energy development (*e.g.*, higher density of roads and facilities) than in more open sage-dominated landscapes with less variable topography. The diverse topography, vegetative cover and ample forage availability in the Piceance Basin appeared to help lessen the severity of indirect impacts to mule deer (*e.g.*, noise, ambient light, and traffic impacts) in this population.[43]

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[40] Hebblewhite, *supra* note 38; Sawyer, *et al.*, *Influence of well pad activity on winter habitat selection patterns of mule deer*, 73 J. Wildlife Mgmt. 1,052 (2008).

[41] Sawyer, *et al.*, *Mule deer and energy development—Long-term trends of habituation and abundance*, 23 Global Change Biology 4,521 (2017); Johnson, *et al.*, *Increases in residential and energy development are associated with reductions in recruitment for a large ungulate*, 23 Global Change Biology 578 (2016).

[42] Sawyer, *et al.*, *Migratory disturbance thresholds with mule deer and energy development*, 84 J. Wildlife Mgmt. 930 (2020); Sawyer, *et al.*, *Long-term effects of energy development on winter distribution and residency of pronghorn in the Greater Yellowstone Ecosystem*, Conservation Sci. & Practice (2019); Sawyer, *et al.*, *supra* note 41; Buchanan, *et al.*, *Seasonal resource selection and distribution response by elk to development of a natural gas field*, 67 Rangeland Ecology & Mgmt. 369 (2014); Sawyer, *et al.*, *A framework for understanding semi-permeable barrier effects on migratory ungulates*, 50 J. Applied Ecology 68 (2013); Wyoming Game and Fish Dep't, *Recommendations for development of oil and gas resources within important wildlife habitats* (2010); Hebblewhite, *supra* note 38; Sawyer, *et al.*, *supra* note 40; Wilbert, *et al.*, *Analysis of Habitat Fragmentation of Oil and Gas Development and Its Impact on Wildlife: A Fragmentation For Public Land Management Planning*, The Wilderness Society (2008).

[43] Peterson, *et al.*, *Reproductive success of mule deer in a natural gas development*

As well densities increase beyond a tolerable threshold in crucial winter habitats and migration corridors, adverse impacts to western big game species are unavoidable and occur from reduced habitat effectiveness regardless of the use of timing limitation stipulations on drilling activities or other site-specific best management practices designed to reduce impacts.[44] Documented adverse impacts include reduced use or abandonment of otherwise high quality habitats in close proximity to development, behavioral shifts in timing and rate of migration, and possible decreased fetal survival rates during periods of environmental stress.[45] Impacts to big game populations are considered extreme when well pad densities exceed four well pads per square mile.[46]

To address the decrease in the habitat effectiveness of crucial big game winter and migratory habitats with increasing density of oil and gas facilities, the Commission has adopted CPW's recommendation of requiring operators to prepare a CPW-approved wildlife mitigation plan to address unavoidable adverse impacts to wildlife resources that occur in these habitats when the development density exceeds one oil and gas location per square mile. This recommendation is consistent with recommendations made by other state fish and game agencies in the Rocky Mountain region.[47] Site-specific circumstances that clearly indicate higher tolerance of development activity, such as those found in the Piceance Basin, will be addressed on

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area, Wildlife Biology (2017); Northtrup, *et al.*, *Quantifying spatial habitat loss from hydrocarbon development through assessing habitat selection patterns of mule deer*, 21 Global Change Biology 3,961 (2015); Lendrum, *et al.*, *Migrating mule deer: effects of anthropogenically altered landscapes*, 8 PLoS ONE (2013); Lendrum, *et al.*, *Habitat selection by mule deer during migration: effects of landscape structure and natural-gas development*, 3 Ecosphere 82 (2012).

[44] Sawyer, *et al.*, *supra* note 41; Wyoming, *supra* note 42; Hebblewhite, *supra* note 38; Sawyer, *et al.*, *supra* note 41.

[45] Sawyer, *et al.* (2020, 2019, & 2013), *supra* note 42; Peterson, *et al.*, *supra* note 43; Northrup, *et al.*, *supra* note 43; Buchanan, *et al.*, *supra* note 43; Seidler, *et al.*, *Identifying impediments to long-distance mammal migrations*, 29 Conservation Biology 99 (2014); Lendrum, *et al.* (2013 & 2012), *supra* note 43; Beckmann, *et al.*, *Human mediated shifts in animal habitat use: Sequential changes in pronghorn use of a natural gas field in Greater Yellowstone*, 147 Biological Conservation 222 (2012).

[46] Lutz, *et al.*, *Energy Development Guidelines for Mule Deer*. Mule Deer Working Group, Western Association of Fish and Wildlife Agencies (2011); Wyoming, *supra* note 42; Wilbert, *et al.*, *supra* note 42.

[47] Wyoming, *supra* note 42; Lutz, *et al.*, *supra* note 46.

a case-by-case basis as part of the wildlife mitigation plan.

On August 19, 2019, Colorado Governor Jared Polis signed Executive Order D 2019-011, *Conserving Colorado's Big Game Winter Range and Migration Corridors*. The Commission's adoption of Rule 1202.d for big game winter range and migratory habitats facilitates the implementation of Governor Polis' Executive Order D 2019-011 and is also complementary to the U.S. Department of Interior Secretarial Order No. 3362, *Improving Habitat Quality in Western Big-Game Winter Range and Migration Corridors*.

<u>Rules 1202.d.(5) and (8). Greater sage-grouse priority habitat management areas and Gunnison sage-grouse occupied habitat and production areas</u>

The Commission has adopted CPW's recommendation that GrSG priority habitat management areas and GuSG occupied habitat and production areas be included in Rule 1202.d and require compensatory mitigation under Rule 1203.a. This decision was based on the body of peer-reviewed scientific literature contained in Attachments 3 and 4 indicating that significant reductions in male lek attendance (widely utilized to measure and track sage-grouse population status) occur at well pad densities greater than one per square mile.[48] Additionally, negative influences on nest and brood survival,[49] and winter range utilization have been observed at oil and gas densities greater than or equal to one well pad per square mile.[50] Finally, this management recommendation is consistent with BLM's 2015 and 2019 Northwest Colorado Greater Sage-grouse Approved Resource Management Plan Amendments that set thresholds for anthropogenic disturbance of 3% overall disturbance and one

[48] Green, *et al.*, *Investigating impacts of oil and gas development on greater sage-grouse*, 81 J. Wildlife Mgmt. 46 (2017); Gregory & Beck, *Spatial heterogeneity in response of male greater sage-grouse lek attendance to energy development*, 9 PLoS ONE (2014); Hess & Beck, *Disturbance factors influencing greater sage-grouse lek abandonment in north-central Wyoming*, 76 J. Wildlife Mgmt. 1,625 (2012); Doherty, *et al.*, *A currency for offsetting energy development impacts: horse-trading sage-grouse on the open market*, 5 PLoS ONE 1 (2010); Harju, *et al.*, *Thresholds and time lags in effects of energy development on greater sage-grouse populations*, 74 J. Wildlife Mgmt. 437 (2010).

[49] Kirol, *et al.*, *Greater sage-grouse response to the physical footprint of energy development*, 84 J. Wildlife Mgmt. 989 (2020).

[50] Holloran, *et al.*, *Winter habitat use of greater sage-grouse relative to activity levels at natural gas well pads*, 79 J. Wildlife Mgmt. 630 (2015); Carpenter, *et al.*, *Sage-grouse habitat selection during winter in Alberta*, 74 J. Wildlife Mgmt. 1,806 (2010); Doherty, *et al.*, *Greater sage-grouse winter habitat selection and energy development*, 72 J. Wildlife Mgmt. 187 (2008).

facility per square mile within GrSG priority habitat management areas.

CPW-conducted research has found that greater sage-grouse in the Parachute-Piceance-Roan ("PPR") population of northwest Colorado appear to tolerate higher levels of anthropogenic disturbance (*i.e.*, higher density of facilities and roads) during the summer-fall season, but not during the breeding and winter seasons.[51] These results differ from a bulk of the available literature conducted in more arid and less naturally fragmented sagebrush ecosystems. Results from this research and analysis of seasonal habitats present at a proposed location will be addressed on a case-by-case basis in the PPR population as part of the wildlife mitigation plan.

While there is not a large body of oil and gas development literature specific to GuSG, GrSG and GuSG are so closely related that the behavioral and distribution responses documented in the research summarized in Attachment 4 for GrSG are applicable to both species. As a federally listed threatened species, GuSG is subject to federal regulatory requirements under the federal ESA. The USFWS Recovery Implementation Strategy ("RIS") for GuSG identifies a specific goal of reducing route density within four miles of leks.[52] The Commission and CPW have chosen to provide additional protections by incorporating GuSG occupied habitat and production areas in Rule 1202.d and requiring compensatory mitigation under Rule 1203.a because of the significant investment Colorado has made in the conservation of this species and the state's interest in having it delisted.

Rules 1202.d.(6) and (10) Columbian sharp-tailed grouse production areas and plains sharp-tailed grouse production areas

CPW maps CSTG and plains sharp-tailed grouse ("PSTG") production areas as a 2 km (1.24 miles) buffer around active dancing grounds (*i.e.*, lek sites). This distance from lek sites is shown to capture 72–80% of sharp-tailed grouse nesting and brood-rearing habitat in Colorado.[53] Studies from other sharp-tailed grouse populations have also demonstrated that a majority of both male and female sharp-tailed grouse remain within this buffer distance from the lek of capture through summer and fall, following the spring lekking season.[54] Based on these studies, and available

[51] Walker, *et al.*, *Quantifying habitat loss and modification from recent expansion of energy infrastructure in an isolated, peripheral greater sage-grouse population*, 255 J. Envtl. Mgmt. (2020).

[52] USFWS, *supra* note 18.

[53] *Columbian Sharp-tailed grouse reproductive ecology and chick survival in restored grasslands of northwest Colorado* (Thesis, University of Wisconsin-Madison 2019).

[54] Boisvert, *et al.*, *Home range and seasonal movements of Columbian sharp-tailed*

literature on the effects of energy development on CSTG, PSTG, and other western grouse species described in Attachments 3 and 4, the Commission has adopted CPW's recommendation that CSTG and PSTG production areas be included in Rule 1202.d and require compensatory mitigation under Rule 1203.a to minimize adverse impacts to these important habitat areas.

Rule 1202.d.(7). Greater prairie-chicken

Greater prairie-chickens require large areas of intact grasslands for nesting and raising broods. Although historical agricultural conversion contributed to previous declines, fragmentation from anthropogenic structures is becoming an increasing cause for concern.[55] CPW maps greater prairie-chicken production areas as a 2.2-mile buffer around active lek sites. Greater prairie-chicken lek sites are generally found in areas with suitable nesting cover as well as brood rearing habitat.[56] Female home ranges tend to be smaller during the nesting period and relatively close to lek sites. Research in northeast Colorado documented that females nest within an average of 0.6 miles (1.0 km) from the closest lek,[57] and research in Kansas found the center of female home ranges averaged 0.6 miles (1 km) from the nearest lek during the breeding season and 1.6 miles (2.5 km) during the non-breeding season.[58] Some greater prairie chicken studies have shown avoidance of roads, powerlines, and oil and gas wells.[59] Winder *et al.* estimated that a focal buffer distance around leks of

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grouse associated with Conservation Reserve Program and mine reclamation lands, 65 W. N. Am. Naturalist 36 (2005); Collins, *Ecology of Columbian sharp-tailed grouse breeding in coal mine reclamation and native upland cover types in northwestern Colorado* (Thesis, University of Idaho 2004); Apa, *Habitat use and movements of sympatric sage and Columbian sharp-tailed grouse in southeastern Idaho* (Dissertation, University of Idaho 1998).

[55] Londe, *et al.*, *Female greater prairie-chicken response to energy development and rangeland management*, 10 Ecosphere (2019).

[56] Powell, *et al.*, *Management of Sandhills rangelands for greater prairie-chickens*. University of Nebraska-Lincoln (2015); Robb & Schroeder, *Greater Prairie-Chicken* (Tympanuchus cupido): *A Technical Conservation Assessment*, U.S. Forest Service, Rocky Mountain Region - Species Conservation Project (2005).

[57] Schroeder, *Movement and lek visitation by female greater prairie-chickens in relation to predictions of Bradbury's female preference hypothesis of lek evolution*, 108 The Auk 896 (1991).

[58] Winder, *et al.*, *Space use of female greater prairie-chickens in response to fire and grazing interactions*, 70 Rangeland Ecology & Mgmt. 165 (2017).

[59] Londe, *et al.*, *supra* note 55; Harrison, *et al.*, *Nest site selection and nest survival*

3.5 miles (5.6 km) was necessary to capture 95% of the breeding and nonbreeding space use of females around a lek.[60] Finally, a University of Nebraska – Lincoln study suggests keeping at least 30–50% of lands within one mile of leks as hospitable nesting grounds to help maintain and increase greater prairie-chicken populations.[61]

Based on these studies, and available literature on the effects of energy development on other western grouse species described in Attachments 3 and 4, the Commission has adopted CPW's recommendation that greater prairie-chicken production areas be included in Rule 1202.d and require compensatory mitigation under Rule 1203.a to minimize adverse impacts to these important habitat areas to continue to sustain and grow the population of this species in Colorado.

Rule 1202.d.(9) Lesser prairie-chicken focal areas

The Commission has adopted CPW's recommendation that lesser prairie-chicken focal areas be included in Rules 1202.d (facility density triggers) and 1203.a (compensatory mitigation triggers) to minimize adverse impacts to these important habitat areas. One of the key components of the conservation strategy outlined in the Lesser Prairie-Chicken RWP is the avoidance of habitat loss and fragmentation within focal areas.[62] The concept of focal areas as applied to lesser prairie-chickens is based on identifying the areas of greatest importance to the species, and focusing habitat enhancement, maintenance, conservation, and protection in these areas. Focal areas mapped in Colorado include the majority of known active leks and nesting locations and are the highest priority in CPW's efforts to recover and maintain stable lesser prairie-chicken populations in the state.

The RWP states specifically that concerns exist that increased well density will result in reduced populations due to loss and degradation of habitat and avoidance behavior exhibited by lesser prairie-chickens.[63] Hunt determined that active lesser prairie-chicken leks had an average of 1 active well within 1 mile (1.6 km) while abandoned leks had an average of 8 active wells within the same distance in the year they were abandoned.[64] Active leks also had fewer miles of roads and power lines when

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of greater prairie-chickens near a wind energy facility, 119 The Condor 659 (2017).

[60] Winder, *et al.*, *supra* note 58.

[61] Powell, *et al.*, *supra* note 56.

[62] Van Pelt, *et al.*, *The Lesser Prairie-Chicken Range-wide Conservation Plan*, Western Association of Fish and Wildlife Agencies (2013).

[63] *Id.*

[64] Hunt, *supra* note 23.

compared to abandoned leks. Road density within 1-mile (1.6 km) lek buffers was 4.4 mile/mile^2 (3.3 km/km^2) for abandoned leks and 3.9 mile/mile^2 (2.4 km/km^2) for active leks. In Texas, lek density was greatest in areas with lower densities of paved roads and lower densities of active oil and gas wells.[65] Studies of GPS-tracked lesser prairie-chickens in Colorado and Kansas showed the relative probability of habitat use decreased as cumulative densities on anthropogenic features increased, with areas having more than two oil wells per 4.9 miles^2 (12.6 km^2, or within a 1.25 mile (2 km) radius) having eight times lower relative probability of use.[66] Distance from oil or gas wells was the most influential anthropogenic feature affecting lek occurrence in Kansas and well density was the most influential feature affecting lek occurrence at the largest scale studied.[67]

Rule 1203.

In Rule 1203, the Commission created alternatives for operators to implement compensatory mitigation for direct impacts or unavoidable adverse indirect impacts to the high priority habitats listed in Rule 1202.d. Distinguishing between direct impacts and unavoidable indirect impacts that would require compensatory mitigation was important throughout the rulemaking process. The Commission clarified that direct impacts include not only wildlife mortality, but also those impacts related to physical land disturbance and vegetation removal resulting in habitat loss. Indirect impacts extend beyond mortality, physical land disturbance, and vegetation removal. Indirect impacts reduce habitat function and effectiveness by affecting wildlife behavior, displacing wildlife to lower quality habitat, decreasing productivity, or impacting survival rates. Indirect impacts may also limit wildlife access to otherwise productive habitats because of their proximity to development and associated human activities.

Under Rule 1203, an operator may fulfill its obligation to complete compensatory mitigation by performing work approved by the Director and CPW, or by paying a habitat mitigation fee to CPW. Rule 1203.a.(3) also provides that an operator to seek an exception from the Director, outside of the ordinary variance process, which may be granted following a consultation with CPW pursuant to Rule 309.e. Rule 1203 is consistent with Senate Bill 19-181's revision to C.R.S. § 34-60-128(3)(b), which contemplates offsite compensatory mitigation. Rule 1203 is also consistent with the Commission's prior 100 Series Definition of "Mitigation," which included off-site habitat mitigation and mitigation banking, and prior Rule 1202.a, which

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[65] Timmer, *et al.*, *Spatially explicit modeling of lesser prairie-chicken lek density in Texas*, 78 J. Wildlife Mgmt. 142 (2014).

[66] Sullins, *et al.*, *supra* note 25.

[67] Jarnevich & Laubhan, *Balancing energy development and conservation: a method utilizing species distribution models*, 47 Envtl. Mgmt. 926 (2011).

contemplated mitigation as a way to minimize adverse impacts to wildlife species and habitats.

Under the framework provided by Senate Bill 19-181, the Commission has structured Rule 1203 in attempt to maintain the current status of the high priority habitats listed in Rule 1202.d in order to preserve and protect habitat functionality. This can also be referred to as a no-net-loss strategy. However, the Commission understands that a determination of the appropriate measures to attain a no-net-loss mitigation goal may vary based on, for example, the complexity of the habitat. While a no-net-loss mitigation strategy meets the statutory requirements for compensatory mitigation as set forth in Senate Bill 19-181, the Commission strongly encourages operators to complete projects or cause projects to be completed with the goal of improving habitat functionality for wildlife resources impacted by oil and gas operations.

Where operators choose to complete mitigation projects to compensate for direct or unavoidable indirect impacts, they may do so, or a third party may do so on their behalf. The Commission has provided an appropriate list of necessary project components to ensure effective projects with measurable results in Rule 1203.b, which include, for example, monitoring and reporting requirements and a mitigation schedule and workplan. The compensatory mitigation plan must also contain the objectives of the project or the mitigation goal, which includes a description of how the plan will address equivalence, timeliness, duration, durability, and additionality. The Director will review any compensatory mitigation plan in consultation with CPW with the understanding that, in certain circumstances, it may be helpful to consider input from relevant local governments or local conservation districts.

The Commission received robust feedback on the concept of a mitigation fee and adopted it as an option because, in some cases, it may be the most effective and efficient way to accomplish compensatory mitigation. Payment of a fee is an alternative compliance mechanism that operators may choose, not a mandate. Whether a fee is appropriate on federal surface estate will be coordinated with BLM on a case by case basis to assess how the federal government will consider the state's recommendation to minimize or mitigate impacts from the proposed operation. The Commission's intention is to build a process that allows for compliance with both NEPA and state processes.

The Commission included a tiered approach to the direct impact mitigation fee in Rule 1203.c. In both the Commission's and CPW's experience, the vast majority of oil and gas locations in Colorado are less than 11 acres. Therefore, the Commission and CPW have more experience understanding the direct impacts to wildlife resources associated with oil and gas locations that are less than 11 acres, which makes imposition of a flat fee most appropriate for those locations. Larger locations are unusual and will require a more in-depth review to understand and mitigate direct impacts. The FAQ in Attachment 1 provides additional information about how the compensatory mitigation fee was calculated for oil and gas locations less than 11 acres, and how a similar methodology would be applied on a case by case basis to larger locations. The fixed fee for locations less than 11 acres can be adjusted by the Commission, as appropriate, with changes to costs over time. Accordingly, the Commission intends to review the direct impact habitat mitigation fee annually. As part of future fee updates, the Commission intends to consider information including, but not limited to, regional and aquatic habitat considerations, as well as the possibility of adopting a per-acre fee. Fees paid by operators will be spent on planned habitat enhancement projects, conservation easements, or other relevant projects intended to benefit the species and habitats impacted by oil and gas operations within CPW's four regions. However, fees may not always be applied directly to the region or species where they were collected, if better results for achieving the state's goals can be achieved by aggregating funds to do larger projects in other areas or for other species. This fee system achieves necessary flexibility in implementation while remaining consistent with the Commission's statutory authority and obligation to minimize adverse impacts to wildlife resources.

As described more fully in the discussion of Rule 904 above, the Commission intends to annually evaluate cumulative impacts regarding multiple categories of resources, including wildlife resources. To ensure the Commission remains informed on impacts to wildlife resources, compensatory mitigation fee spending, and the details of ongoing mitigation projects, data on these topics will be included in the annual report. Such data will include information on the progress, monitoring, and effectiveness of mitigation projects, information included in the Commission's CIDER database, and information on the collection and allocation of the direct and indirect impact habitat mitigation fees. The Director will then include such information in an annual report to the Commission as provided for in Rule 904.a.

Rule 1203.d requires mitigation of unavoidable adverse indirect impacts to the high priority habitats listed in Rule 1202.d. This narrow approach to mitigation of only unavoidable adverse indirect impacts appropriately prioritizes avoidance first, then minimization, and finally mitigation where avoidance and minimization are insufficient to meet the goal of sustaining a robust and sustainable wildlife population.

Rule 1203.d will be applied when the oil and gas location density is less than five locations per square mile. The Commission intends for its Staff, working with CPW, to issue guidance describing how to appropriately calculate the oil and gas location density. The rationale for this location density and its relationship to unavoidable adverse indirect impacts for the high priority habitats listed in Rule 1202.d is provided in the discussion for Rule 1202.d and the species-specific literature referenced in Attachments 3 and 4. When an oil and gas location is proposed in an area with less than five oil and gas locations per square mile, CPW may consider the existing landscape context and the additional factors outlined in Rule 1203.d.(2) when determining whether to recommend compensatory mitigation for unavoidable adverse indirect impacts.

As discussed above and outlined in Rule 1203.a, an operator may fulfill its obligation to complete compensatory mitigation for unavoidable adverse indirect impacts by performing work approved by the Director and CPW, or by paying a habitat mitigation fee to CPW. Due to the variety of site-specific factors described in Rule 1203.d.(2) that determine the extent of unavoidable adverse indirect impacts, the amount of compensatory mitigation that will be required for unavoidable adverse indirect impacts will be determined by the Director and CPW on a case by case basis, in coordination with the operator.

APPENDIX B

Our Children's Trust Petition for Rulemaking

On November 8, 2019, Our Children's Trust ("OCT") submitted a Petition for Rulemaking ("Petition") to the Commission pursuant to then-applicable Rule 529.

OCT's Petition

The OCT Petition expressed serious concerns regarding the impacts of oil and gas development, and provided evidence of air emissions resulting from oil and gas development, including greenhouse gases, as well as contributions to climate change. The Petition also provided evidence of negative impacts to health, safety, and welfare, the environment, and wildlife resources from air emissions, leaks, spills, truck traffic, poor wellbore integrity, improperly abandoned oil and gas equipment, and water consumption. The Petition addressed the negative impacts of climate change and argued that Colorado's energy systems must be decarbonized. Finally, the Petition argued that the oil and gas industry placed an economic burden on Colorado due to the severance tax rate and abandoned wells.

The Petition proposed rules to address OCT's concerns. First, the Petition proposed rules to address cumulative and direct impacts from oil and gas operations. Section 1 of the Petition's proposed rules required the Commission to conduct a periodic baseline assessment of all impacts on public health, the environment, and climate change from oil and gas operations. Section 2 required the Commission to create a climate recovery plan that sets biennial lifecycle greenhouse gas emission reduction targets for Colorado's oil and gas operations. Section 3 required all applications for oil and gas development to include total lifecycle greenhouse gas emissions resulting from proposed operations, information about how the proposed operations would directly and cumulatively impact public health, safety, welfare, the environment, and wildlife resources, and impact on the baseline assessment. Section 4 proposed rules that would prohibit the Commission from approving a permit application unless the application demonstrates there would be no negative impact on the baseline assessment, public health, safety, welfare, the environment, and wildlife resources from the proposed operations, and the application shows that it is in compliance with the proposed climate recovery plan. Section 4 proposed rules requiring operators to submit annual reports with information on operations, greenhouse gas emissions, and impacts to the proposed baseline assessment. The Petition also proposed a rule requiring the Commission to suspend all permitting until the rules proposed in the Petition were effective. Finally, the Petition proposed rules requiring the Commission to establish a climate adaption and mitigation program account, to be funded through fees from operators, which would be used to fund electric heating systems and renewable energy projects.

APPENDIX B

The Commission's Procedure to Address the Petition.

When OCT submitted its Petition, the Commission's rulemaking effort in this 800/900/1200 Mission Change Rulemaking was substantially underway. In the summer and fall of 2019, the Commission embarked on a statewide listening tour to hear from the public about several rulemakings required by Senate Bill 19-181: mission change, cumulative impacts, alternative location analysis, and flowlines. The Director and Commission's Staff also solicited input on policy and Rule changes from stakeholders. On November 1, 2019, the Commission's Staff released the Mission Change Whitepaper. The Whitepaper provided stakeholders and the public with their first look at the Commission Staff's proposed ideas and concepts to implement the provisions of Senate Bill 19-181.

The Administrative Procedure Act provides that while action on any petition is within the discretion of the agency, "when an agency undertakes rule-making on any matter, all related petitions for the issuance, amendment, or repeal of rules on such matter shall be considered and acted upon in the same proceeding." C.R.S. § 24-4-103(7). The Petition proposed rules to address cumulative impacts of oil and gas development, and to protect public health, safety, and welfare, the environment, and wildlife resources. The entire purpose of the 800/900/1200 Mission Change Rulemaking is to adopt rules that protect public health, safety, and welfare, the environment, and wildlife resources as required by Senate Bill 19-181, as well as to adopt rules evaluating and addressing the potential cumulative impacts of oil and gas development. The Commission therefore concludes the Petition is related and it is necessary and appropriate for the Commission to consider and act upon the rules proposed in the Petition as part of this 800/900/1200 Mission Change Rulemaking.

OCT was a party to the 800/900/1200 Mission Change Rulemaking and submitted prehearing statements requesting that the Commission adopt the rules proposed in the Petition. On June 26, 2020, the Commission's Hearing Officer issued a Case Management Order ("CMO") which notified all parties that the Commission would consider the Petition in this rulemaking. That CMO also allowed the parties to file responses to the Petition. Sixteen parties filed such responses. During the related, but distinct 200–600 Mission Change Rulemaking hearing, OCT presented its arguments and proposed rules, and the 16 parties who filed written responses presented arguments in response to the OCT petition.

Further, because OCT was a party and requested the Commission adopt the rules proposed in the Petition in OCT's written submissions, the Commission was obligated to consider the rules proposed in the Petition regardless of whether the Commission would have granted the Petition, just as the Commission considers proposed rules suggested by all parties to every rulemaking. The question of whether to grant the Petition is thus moot, because the Commission has addressed the substantive regulations proposed by the Petition in the course of the 800/900/1200 Mission Change Rulemaking (and related but distinct 200–600 Mission Change Rulemaking).

Commission Response to OCT's Concerns and Proposed Rules

For the following reasons, the Commission declines to adopt the specific regulatory text proposed in the Petition, although the Commission adopted several Rules intended to address some similar concepts and concerns to those raised in the Petition. This Statement of Basis and Purpose reflects the Commission's consideration of OCT's concerns and response to the rules proposed by the Petition. The Commission therefore relies on the entire Statement of Basis and Purpose as its consideration and response to the rules proposed by the Petition. However, the Commission included the following section in this Statement of Basis and Purpose to directly address the Petition.

Prior Rulemakings

In November 2019, after OCT submitted its Petition, the Commission held a rulemaking hearing to revise its flowline rules as required by Senate Bill 19-181. In the 2019 Flowline Rulemaking, the Commission amended its 1100 Series Rules to require location data for flowlines, required that the data be publicly available, enabled the Commission's Staff to conduct timely inspections when inactive flowlines or wells are returned to service, and improved protection of public health, safety, welfare, the environment, and wildlife resources by updating and strengthening the Commission's flowline abandonment Rules. The 2019 Flowline Rulemaking addressed OCT's concerns regarding emissions, leaks, and spills from flowlines, as well as concerns with abandoned flowlines.

In June 2020, the Commission updated its wellbore integrity rules, as required by Senate Bill 19-181. In the Wellbore Integrity Rulemaking, the Commission adopted its wellbore monitoring and testing rules by requiring bradenhead monitoring and testing, updated its standards to ensure that operators isolate groundwater, set safety and environmental protections during drilling and hydraulic fracturing operations, strengthened standards for casing and cementing, updated standards to prevent blowouts, and updated well plugging standards. The Wellbore Integrity Rulemaking addressed OCT's concerns regarding wellbore integrity and improperly abandoned wells.

To the extent necessary to address the Petition, the Commission adopts the Statements of Basis and Purpose for the 2019 Flowline Rulemaking and Wellbore Integrity Rulemaking.

200–600 & 800/900/1200 Mission Change Rulemakings

The following discussion demonstrates the Commission's consideration of and decision on the rules proposed by the Petition, though it is not intended to be a complete discussion of all Commission Rules that are intended to address concerns raised by the Petition.

The 800 Series Rules regulate underground injection control wells to avoid, minimize, and mitigate adverse impacts to groundwater and surface water.

The 900 Series Rules regulate venting and flaring of natural gas and emissions from pits to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and are specifically intended to reduce emissions of greenhouse gases and other air pollutants from oil and gas operations. Specifically, Rule 904 requires the Director to provide an annual report to the Commission on data gathered in CIDER and CDPHE's ongoing efforts to reduce greenhouse gas emissions and implement House Bill 19-1261. The Commission intends to use data from CIDER, in cooperation with CDPHE and other partners, to undertake basin-wide, statewide, and other studies to evaluate cumulative impacts to relevant resources at appropriate scales.

The 1200 Series Rules are intended to protect and minimize adverse impacts to wildlife resources through planning, special protections for sensitive areas, and compensatory mitigation.

The Commission completed the 800/900/1200 Mission Change Rulemaking and 200–600 Mission Change Rulemaking on the same day. Many Rules adopted in the 200–600 Mission Change rulemaking are responsive to the concerns raised in the OTC petition.

Rule 303.a.(5), which creates CIDER, is intended to create baseline dataset that can be used to facilitate the Commission's ongoing efforts to evaluate the cumulative impacts of oil and gas operations in Colorado. Additionally, in Rules 303.a.(5).B.i & ii, the Commission required operators to submit estimated emissions of specific pollutants. Based on consultation with CDPHE, the Commission carefully selected a necessary and reasonable set of indicator pollutants that are particularly relevant to impacts on public health and the environment, because of their direct health impacts, role in tropospheric ozone formation, and contribution to climate change. Together, Rules 303.a.(5) and 904 implement the Commission's evaluation of cumulative impacts, including cumulative impacts of greenhouse gases that contribute to climate change.

The discussion of Rule 303.a.(5) in the Statement of Basis and Purpose for the 200–600 Mission Change Rulemaking provides additional details and identifies additional

Rules intended to address and evaluate cumulative impacts. Rule 303.a.(5) and related Rules respond to and address the same concerns that led OCT to propose its baseline assessment rule. The Commission also does not intend for the 200–600 and 800/900/1200 Mission Change Rulemakings to be the final, or only, rulemaking to evaluate and address cumulative impacts, and the Commission will continue to coordinate with CDPHE and other partners to evaluate data in the CIDER database and other information salient to evaluating and addressing cumulative impacts.

Other Commission Rules adopted in the 200–600 Mission Change Rulemaking are intended to address cumulative impacts. These Rules include Rule 314, governing CAPs, Rule 304.c.(19), requiring operators to submit a cumulative impacts plan, and Rules 603.d and e, governing well consolidation and development from existing locations. Additionally, Rules 423, 424, 426, and 427 provide substantive standards to address cumulative noise, light, odor, and dust impacts, respectively.

The Commission also adopted Rules to reduce air emissions, including greenhouse gases. For example, numerous 300 Series Rules are intended to facilitate greenhouse gas emissions reductions, including Rules 303.a.(5).B.i, 304.c.(12), 304.c.(19), and 314.e. Many of these Rules are specifically intended to facilitate the capture of natural gas to avoid routine venting and flaring, and to facilitate electrification which results in significant emissions reductions. In drafting these Rules, the Commission's Staff worked closely with AQCC, which is conducting rulemakings to implement a statewide plan to reduce greenhouse gas emissions as directed by House Bill 19-1261. House Bill 19-1261 sets a goal of gradually eliminating statewide greenhouse gas emissions in approximately the next 50 years. In adopting and implementing Rules in this 200–600 Mission Change Rulemaking the Commission intends to work with AQCC's effort to reduce greenhouse gases, thereby addressing the Petition's concerns.

The Commission adopted Rule 604, which increased the distance oil and gas facilities must be located from school facilities and child care centers and set a presumptive distance of 2,000 feet from all building units. Rule 604 is intended to be another regulatory tool to avoid, minimize, and mitigate impacts on public health and welfare from air emissions, noise, light, dust, and other conditions.

The Petition proposes a rule that the Commission may not grant any permit unless an operator shows by "clear and convincing evidence" that a proposed oil and gas operation will not have any adverse impact on public health, safety, welfare, the environment, and wildlife resources. Senate Bill 19-181's changes to the Commission's mission and statutory authority direct the Commission to "regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health." C.R.S. § 34-60-106(2.5)(a). Senate Bill 19-181 also defined "minimize adverse impacts" to mean "to the extent necessary and reasonable to protect public health, safety, and welfare, the environment, and wildlife resources, to: (a) Avoid adverse impacts from oil and gas operations; and (b) Minimize and mitigate the extent and severity of those impacts that cannot be avoided." C.R.S. § 34-60-103(5.5). This standard demonstrates that the General Assembly recognized that some impacts are unavoidable, though unavoidable impacts should be minimized and mitigated. Adopting a rule that sets a no adverse impacts standard, as requested by OCT, would be contrary to the express language of Senate Bill 19-181 and that legislative intent.

It is not necessary or appropriate for the Commission to adopt the Petition's proposed rule that no new permits will be issued until the Rules adopted in the 800/900/1200 Mission Change Rulemaking are effective. Senate Bill 19-181 provided the Director with a process to continue permitting, and with a process to delay decisions on permit applications which require additional consultation or analysis to ensure protection of public health, safety, and welfare or the environment until rules mandated by Senate Bill 19-181 are effective. C.R.S. § 34-60-106(1)(f). The Commission and its Staff have been implementing this process of delaying permitting decisions since the adoption of the statute. Further, Senate Bill 19-181 "applies to conduct occurring on or after the effective date of this act, including determinations of applications pending on the effective date," and therefore applies to any pending or subsequently filed application. Senate Bill 19-181 § 19. The Director thus must ensure that any permit applications pending on or submitted after April 16, 2019 meet the standards set by Senate Bill 19-181. The Commission therefore concluded that, pursuant to this authority, it is not necessary or reasonable to halt all permitting until the Mission Change Rulemakings Rules are effective because the Director has ensured and will continue to ensure that either any permitted location meets the standards set by Senate Bill 19-181 or will delay a permit application until the Mission Change Rulemakings Rules are effective.

The General Assembly did not grant the Commission with the authority to adopt the Petition's proposed rule creating a climate adaptation and mitigation account. The Oil and Gas Conservation Act, as amended by Senate Bill 19-181, provides the Commission with authority to adopt permitting fees to cover the reasonably foreseeable direct and indirect costs of regulating oil and gas operations. C.R.S. § 34-60-106(7)(b). But it does not provide the Commission with the authority to create the fund proposed by the Petition which goes beyond the Commission's regulatory scope of regulating "oil and gas operations," *see, e.g.*, C.R.S. §§ 34-60-103(6.5), 34-60-106(2.5)(a), for example, by funding residential electric heating systems.

Finally, the Commission does not have the statutory or constitutional authority to alter the severance tax rate and therefore did not take action on the Petition's concerns with Colorado's tax on oil and gas production. The Commission is planning to hold a rulemaking in 2021 to address financial assurance, as directed by Senate Bill 19-181. *See* C.R.S. § 34-60-106(13). The Commission's current orphan well program is also addressing orphaned wells in Colorado. The Commission therefore determined it was not necessary to address the Petition's argument regarding the economic burden on Colorado posed by orphan wells in the 800/900/1200 Mission Change Rulemaking.

Conforming Changes

All conforming changes are described in the "Amendments and Additions to the Rules" section above.

Effective Date

The Commission adopted the proposed amendments during its hearing held between October 6 and November 23, 2020. Pursuant to C.R.S. § 24-4-103(5), these amendments will become effective on January 15, 2021, unless otherwise specified in the Rule.

ATTACHMENT 1

COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources

COLORADO
Parks and Wildlife
Department of Natural Resources

FAQ for October 9, 2020 Draft Wildlife Rules

1) What is High Priority Habitat, and what happened to Sensitive Wildlife Habitat and Restricted Surface Occupancy Areas from the previous Rules?

When the Commission promulgated rules to implement HB 07-1298 in 2009, CPW was tasked with providing a list of species-specific High Priority Habitats ("HPH") in Colorado along with recommendations for management actions that may be implemented during oil and gas development to avoid, minimize, and mitigate impacts to those species and habitats.

CPW's recommendations were developed internally by a team of subject matter experts who consulted with peers in other agencies and academic institutions. While the HPH list does not cover all wildlife species in Colorado, it covers those species and habitats that CPW is concerned about and for which CPW has spatial data and reliable information (peer-reviewed published research) to make management recommendations for wildlife protection during oil and gas development operations.

In 2009, subsets of HPH were re-labeled Sensitive Wildlife Habitat ("SWH") or Restricted Surface Occupancy ("RSO") areas. For the 800/900/1200 Mission Change Rulemaking, the Commission chose to simplify the nomenclature and mapping to be consistent with how CPW categorizes, labels, and maps these species activities and habitats. The HPH identified in new Rule 1202.c.(1) are analogous to the RSO areas under the previous Rules. Similarly, the remaining CPW-mapped habitat consultation triggers referenced in new Rule 309.e.(2) are analogous with SWH areas in the prior Rules. All HPH maps will be incorporated into Appendix VII and will be updated periodically, but not more than annually, through the rulemaking process.

2) What is an Alternative Location Analysis described in Rule 304.b.(2).B.viii?

For oil and gas locations proposed in HPH for wildlife, an operator should consider alternative locations that either avoid the habitat altogether, or, where avoidance is not feasible, consider locations that minimize adverse impacts to the maximum extent possible. The most efficient method for CPW to work with operators on locating facilities is during the pre-application period. During the pre-application period, CPW may review potential locations with an operator to minimize adverse impacts to wildlife. During this informal "pre-consultation," CPW can waive the wildlife portion of the Alternative Location Analysis ("ALA") submitted with the Form 2A, Oil and Gas Location Assessment application if an operator demonstrates that it has selected a location that avoids and minimizes impacts to wildlife. If a pre-application waiver is not acquired from CPW through this process, the operator will submit an ALA with their Form 2A application that addresses impacts to wildlife. The ALA will contain information on alternative locations that were considered to avoid and minimize impacts to wildlife, and a narrative explaining why these locations were ultimately not feasible for locating the proposed oil and gas facilities.

3) Under previous rules the consultation period for CPW was 40 days; now it is 60 days. Won't this cause unnecessary delays in permitting?

On average, CPW has historically completed Form 2A consultations in significantly less time than the 40-day consultation period provided for in prior Rule 306.c.(2).C. The addition of 20 days is intended to allow additional time for those instances where compensatory mitigation projects must be negotiated as a substitute for the flat Direct Impact Habitat Mitigation Fee (Table 1203-1) or to address unavoidable adverse indirect impacts. In rare instances where the consultation process may include more complex discussions regarding wildlife protections, additional time may be necessary to facilitate these negotiations. The full 60-day consultation period will likely not be necessary at a substantial number of wildlife consultations that do not require compensatory mitigation.

4) How will the consultation process be implemented on federal surface or minerals?

The Commission and CPW currently enjoy a productive and cooperative relationship with respect to permitting on federal surface. The Commission will continue to adhere to the longstanding Memorandum of Understanding with its federal partner agencies, the Bureau of Land Management and the U.S. Forest Service, for permitting processes on federal surface and mineral estate. In addition, CPW routinely provides input regarding wildlife and wildlife habitat protection during the National Environmental Policy Act ("NEPA") process. The Commission and CPW routinely participate jointly in "onsites" for projects on federal land. Due to the timing of the federal NEPA processes, many of these onsites may occur in the pre-application period for state permits, so the regulatory agencies can work together with the operator to select the least impactful location or agree to site specific measures to reduce impacts. Where mitigation will be necessary for unavoidable adverse impacts, the Bureau of Land Management may provide valuable insight to potential mitigation projects.

5) How do the Rules address consultations for federally listed Threatened and Endangered species in Rule 309.e.(2)?

A proposed Oil and Gas Location or other facility that falls within federally designated Critical Habitat for a Threatened or Endangered species is subject to a CPW consultation under Rule 309.e.(2). The purpose for this consultation requirement is to provide CPW with the opportunity to coordinate with the Commission, the operator, the landowner, and the U.S. Fish and Wildlife Service ("USFWS") on federally listed species for which Colorado also has a state interest. The USFWS has primary jurisdiction and authority for species listed under the Endangered Species Act ("ESA"), and CPW will coordinate closely with USFWS on any management recommendations for these species. The consultation with CPW under Rule 309.e.(2) does not substitute or replace formal consultation under the ESA or any other requirement specified by USFWS under the authority of the federal ESA for federally listed Threatened or Endangered Species.

6) What is a Wildlife Protection Plan, Wildlife Mitigation Plan, or other conservation plan as described in Rules 309.e.(3) and 1201 and how are they different?

Wildlife Protection Plans, Wildlife Mitigation Plans, and other conservation plans are similar in that they all describe operating practices and other measures that will be implemented to avoid, minimize, and in some cases, mitigate impacts to Wildlife Resources.

A **Wildlife Protection Plan** is a plan specific to new or amended Form 2As for Oil and Gas Locations outside of HPH that describes statewide operating practices and measures that will be implemented to avoid, minimize, and mitigate impacts to Wildlife Resources. The required contents of a Wildlife Protection Plan are outlined in Rule 1201.a.

A **Wildlife Mitigation Plan** references a type of plan submitted with new or amended Form 2As within HPH that was originally implemented under previous Rule 1202.d.(2). These plans are agreements between an operator and CPW regarding how to avoid, minimize, and mitigate impacts to Wildlife Resources for either a single location, or for multiple locations on a landscape scale meaningful to address habitat fragmentation and cumulative impacts to wildlife. The required contents of a Wildlife Mitigation Plan are outlined in Rule 1201.b. Some operators have ongoing Wildlife Mitigation Plans, and this concept was carried over into the new Rules. Pre-existing CPW-approved Wildlife Mitigation Plans in effect when the new Rules take effect may meet the requirements of Rule 1201.b, subject to written concurrence from CPW. Although both documents are tools for broader, landscape-level planning, Wildlife Mitigation Plans differ from Comprehensive Area Plans because Wildlife Mitigation Plans address only impacts to Wildlife Resources, and Comprehensive Area Plans address cumulative impacts to all resources and also confer exclusive operatorship over an area.

Other conservation plans refer to plans to avoid, minimize, and mitigate adverse impacts to Wildlife Resources implemented through other programs that are intended to also satisfy, in whole or in part, an operator's need to address impacts to wildlife from the development activities contemplated under the Rules. Examples of other conservation plans may include, but are not limited to: Habitat Conservation Plans for threatened and endangered species, Candidate Conservation Agreements, wildlife plans adopted pursuant to local or federal government regulations, and enrollment in habitat exchanges (if combined with the appropriate impact minimization and avoidance as described in Rules 1202 and 1203).

7) How do the rules address habitat mapping discrepancies or permanent changes to species distribution?

The Commission and CPW recognize that in certain circumstances wildlife habitat maps may lack ground truthing, or a species may have permanently changed its distribution due to land use or habitat changes that make an area mapped by CPW as wildlife habitat incompatible with future use by wildlife. Rule 309.e.(3).C recognizes that there is no need to consult with CPW if an operator and CPW agree that the CPW-mapped habitat and species triggering the potential consultation is no longer present and unlikely to return to the area, or that the proposed Oil and Gas Location is within an area that is either primarily or completely developed for uses that make it incompatible as wildlife habitat.

8) Several of the Rules reference obtaining a "waiver" from CPW (Rules 304.b.(2).B.viii, 309.e.(2).G, 309.e.(5).D, 1202.a, 1202.b, and 1203.a.(3)). How does an operator obtain a waiver from CPW?

Waivers from CPW may be obtained during an informal pre-application consultation or during the formal consultation process that starts when the completeness determination is made for a new or amended Oil and Gas Development Plan for Oil and Gas Locations within High Priority Habitat. CPW may waive the wildlife portion of an Alternative Location Analysis during the pre-application period if the operator has contacted CPW to discuss alternative locations and demonstrated that it has selected a location that avoids and minimizes impacts to wildlife. Likewise, per Rule 309.e.(5).D, CPW may waive any of the operating and mitigation requirements required by Rules 1202 and 1203 if the operator demonstrates to CPW's satisfaction that the protections for Wildlife Resources outlined in Rules 1202 and 1203 are met or exceeded.

9) How are cumulative impacts to Wildlife Resources being addressed in the new rules?

Cumulative impacts to Wildlife Resources occur as direct and indirect impacts aggregate from multiple development activities on the landscape. Several proposed rules are intended to address cumulative impacts. The incorporation of a Wildlife Protection Plan into every new and amended Form 2A located outside of HPH pursuant to Rules 304.c.(17) and 1201.a will reduce direct, indirect, and cumulative impacts to Wildlife Resources. The Wildlife Protection Plan will describe how the operator has incorporated the Rule 1202.a statewide operating practices that are designed to minimize site-specific impacts to Wildlife Resources at the selected location. For new or amended Form 2As located within HPH, a Wildlife Mitigation Plan will be submitted in lieu of a Wildlife Protection Plan. The Wildlife Mitigation Plan will describe an operator's incorporation of Rule 1202.a statewide operating practices, as well as any pre-application ALA completed to avoid impacts to Wildlife Resources, additional Rule 1202.b HPH-specific operating practices, and Rule 1203 compensatory mitigation commitments to offset unavoidable adverse impacts.

The species-specific development buffers outlined in Rule 1202.c.(1) will help reduce cumulative impacts to the applicable species. Likewise, Rule 1202.d provides the opportunity to address cumulative impacts to species known to be adversely impacted by Oil and Gas Location densities in excess of one per square mile. Finally, Rule 1203 requirements to complete compensatory mitigation to offset unavoidable direct and indirect adverse impacts will greatly reduce cumulative impacts to Wildlife Resources.

10) How do the rules provide for access and utility corridors regarding Rule 1202.c.(1): Cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters?

The intent of the aquatic habitat buffers is to protect these habitats to the extent feasible from direct, indirect, and cumulative impacts from proposed oil and gas development activities. The buffer provides an area where new Oil and Gas Locations should not be constructed in order to maintain the integrity of these habitats. The Commission and CPW recognize that due to the linear nature of these aquatic buffers, reasonable access (*e.g.*, roads and pipelines) will need to be provided for Oil and Gas Locations constructed outside of the aquatic buffers. To provide this access in a way that minimizes impacts to aquatic habitats, the Commission and CPW will work with the operator and the landowner on a case-by-case basis to evaluate the best type of crossing structure and least impactful construction schedule to maintain desired levels of aquatic habitat connectivity and minimize impacts to aquatic species' spawning activities. This approach is captured in Rule 1202.c.(2).C. The Commission and CPW do not intend for the aquatic habitat buffers to preclude reasonable access to Oil and Gas Locations.

11) Is it appropriate to include intermittent and ephemeral streams in the native fish and other native aquatic species conservation waters and sportfish management waters layers?

Multiple scientific publications support the importance of ephemeral and intermittent streams to native and sportfish species. Please review the Statement of Basis and Purpose and Attachments 3 and 4 to read the scientific publications supporting this recommendation. The use of these habitat types is oftentimes short in duration and seasonal, but it is critical to the life history of many species with respect to spawning, rearing, refuge, foraging, and dispersion. These stream types can be completely devoid of water for most of the calendar year, but heavily used for the short period of time in which water is present. During droughts, these streams may be dry for one or more consecutive years. A primary example of this is Cottonwood Creek, a tributary in the Gunnison River Basin, which is dry for much of the year but supports large amounts of native species spawning when seasonal flows are present. A photographic exhibit is available in the Statement of Basis and Purpose.

Not all intermittent and ephemeral streams in Colorado are included in the native fish and other native aquatic species conservation waters and sportfish management waters layers. Only intermittent and ephemeral streams that are relevant to native fish and other native aquatic species conservation waters and sportfish management waters are included.

Of all the USGS-mapped National Hydrography Dataset ("NHD") features in Colorado, only 22.4% of streams and 65.5% of larger water bodies in the State are categorized by CPW for fisheries management. Approximately 10.2% of NHD streams are identified as sportfish management waters and 6.1% of NHD streams are identified as native fish and other aquatic species streams. These two management categories often include tributaries that support downstream habitats through the provision of a number of services, some of which are detailed above. These layers were developed by aquatic biologists for fisheries management purposes but their origins do not preclude use in other efforts.

12) What is the definition of a lek site as used in Rule 1202.c.(1).A–F?

A lek site is a relatively open area or area of low vegetative cover where Colorado's grouse species traditionally display and breed in the spring. A lek site as listed in Rule 1202.c.(1) refers to a lek with lekking activity in any year during the previous 10 years. Historic leks, *i.e.*, leks with no activity within the last 10 years, are not included in Rule 1202.c.(1). Lek sites are mapped with a buffer zone surrounding the lek location with the species-specific buffer distances listed in Rule 1202.c.(1).

Where species-specific lek buffers are known to extend beyond suitable habitat, CPW may work with an operator on a case-by-case basis and provide support for a variance request to allow development within the NSO buffer.

13) How are "active nests" defined for Rule 1202.c.(1).G–L?

An active nest is defined by CPW as any known nest for these species that has been verified as occupied during at least one year out of the previous five years. Inactive nests, *i.e.*, not occupied within last five years, are not included in Rule 1202.c.(1).

14) How does an operator fulfill the obligation to complete compensatory mitigation to satisfy Rule 1203 in a timely way that doesn't delay their permit?

The Commission and CPW both recognize that processing Form 2As that require compensatory mitigation under Rule 1203 will likely require additional staff time and collaboration with operators. To accommodate this increased workload for this subset of consultations, the consultation period outlined in Rule 309.e.(4).B has been extended to 60 days, as referenced above.

It is important to note that an operator is not expected to complete a compensatory mitigation project prior to or during the time that a permit application is subject to review and consultation. But it is necessary for the compensatory mitigation plan to be agreed upon during the consultation. If an operator chooses to pay a habitat mitigation fee, the payment of a that fee will be tied to the Form 42, Notice of Construction submittal date, so that the operator is not required to put forward funds until the disturbance is imminent.

The Commission and CPW have worked with operators in Colorado that own or have access to property suitable for completing compensatory mitigation projects. In addition, operators often have qualified staff and subcontractors to implement mitigation projects. Another option is for the operator to engage a third-party habitat exchange, such as the Colorado Habitat Exchange, to determine if there are projects that have already been completed that would satisfy the mitigation requirement. During the consultation period, the operator and CPW will work together to determine an appropriate schedule and the most efficient way to complete the mitigation obligation. The results of this discussion will be incorporated as a recommended permit condition of approval.

15) How was the Direct Impact Habitat Mitigation Fee (Table 1203-1) calculated and how will CPW spend the mitigation money that it collects?

The Direct Impact Habitat Mitigation Fee was calculated by averaging the statewide disturbance acreage values from Form 2A locations submitted over the last two years (2018 & 2019). These acreage values include an average long-term disturbance (*i.e.*, working pad and access road surface) and average short-term disturbance (*i.e.*, areas where interim reclamation occurs following construction). These two averages were multiplied by the long-term and short-term compensatory mitigation costs. Long-term mitigation costs were obtained from the Department of Local Affairs' five-year (2014–19) average cost per acre to implement permanent conservation easements in Colorado. Short-term mitigation costs were obtained by averaging CPW's recent costs to implement short-term habitat enhancement projects in Colorado. The sum of the long- and short-term calculations is the overall Direct Impact Habitat Mitigation Fee for proposed locations between 1.0 and 10.99 acres. For Oil and Gas Locations 11 acres and larger, CPW will use a similar methodology to calculate the short- and long-term disturbance on a site-specific basis, and work with operators to calculate the Direct Impact Habitat Mitigation Fee necessary to offset direct impacts to Wildlife Resources at each site.

CPW intends to spend mitigation funds annually on planned habitat enhancement projects, conservation easements, or other relevant projects intended to benefit the species and habitats impacted by oil and gas operations within CPW's four regions.

16) What are "indirect impacts" referenced in Rule 1203.d, and how does CPW intend to address them?

Direct impacts are those related to physical land disturbance and vegetation removal resulting in habitat loss. Indirect impacts extend beyond the physical disturbance and vegetation removal. Indirect impacts reduce habitat function and effectiveness by affecting wildlife behavior, displacing wildlife to lower quality habitats, and decreasing productivity and/or survival rates. Indirect impacts may also limit wildlife access to otherwise productive habitats because of their proximity to development and associated human activities.

Indirect impacts include habitat fragmentation from roads and traffic, wells, and ancillary facilities. Negative effects to Wildlife Resources from indirect impacts are well documented in scientific literature. Indirect impacts to wildlife from oil and gas development activities are most pronounced when surface development expands from low density (one or fewer Oil and Gas Locations per square mile) to high density (five or more Oil and Gas Locations per square mile). The factors that may be used by CPW to evaluate and assess the cumulative functional habitat loss from fragmentation and modified habitat use are listed in 1203.d.(2). CPW will use those factors to determine if additional compensatory mitigation is warranted to offset residual unavoidable adverse impacts for individual Form 2As during the consultation with operators.

ATTACHMENT 2

COGCC Mission Change Rulemakings Reorganization Crosswalk

As part of its 200–600 and 800/900/1200 Mission Change Rulemakings, the Colorado Oil and Gas Conservation Commission has reorganized several series of its Rules. This reorganization improved clarity for all stakeholders by grouping all Rules addressing similar topics together in the same Series. Additionally, the order of the Rules within each Series is now in a more logical, sequential order that better reflects the sequential processes that occur on the ground. The Tables below show both the prior and reorganized Rule numbers

Prior Rule Number	Reorganized Rule Number
201	201
202	202
203	203
204	204
205	206; 208
205A	201; 208
206	207
207	209
208	210; 211
209	212
210	605
211	214
212	601
213	*Removed.*
214	215
215	216
216	314
301	206; 213
302	205; 302
303	301; 302; 303; 304; 308; 310; 311.
304	306
305A	302; 309
305	302; 306; 307; 309; 406; 412; 605
306	302; 309; 529
307	404
308A	414
308B	416
308C	206, 223
309	413
310	217

311	435
312	218; 219
313	*Removed*
313A	*Removed*
313B	220
314	420
315	409
316A	808
316B	418
316C	405
317	408; 603; 903
317A	*Removed*
317B	411
318	401
318A	402; 615
318B	403
319	434
320	201
321	410
322	415
323	909
324A	801; 902
324B	802
324C	805
324D	914
325	801; 803; 804; 806; 807; 809; 810
326	417
327	428
328	429
329	430
330	431
331	432
332	433
333	313; 405; 436
334	221
335	908
336	222
337	912
338	*Removed*
339	*Removed*
340	913
341	419
401	220; 811

402	811
403	803; 804; 811
404	803; 804; 811
405	803; 811
501	501
502	502; 503
503	503
504	503
505	501
506	503; 510
507	504
508	511
509	507; 509; 510; 518
510	512
511	505; 508; 510
512	513
513	529
514	*Removed*
515	530
516	514
517	515
518	516; 517
519	517
520	*Removed*
521	522
522	510; 523; 524; 528
523	525
524	526
525	527
526	510
527	509
528	507; 510
529	529
530	506
531	519
532	520
533	521
601	601
602	602
603	421; 602; 603; 604; 605; 606; 607; 608
604	304; 408; 412; 603; 604; 606; 608; 610; 903
605	603; 605; 608
606A	610

606B	611
607	612
608	614; 615
609	615
610	613
801	422
802	423
803	424
804	425
805	426; 427; 608; 903
901	901
902	909
903	908
904	910
905	911; 913
906	912
907	427; 905
907A	906
908	907
909	911; 913
910	915
911	*Removed*
912	903
1201	304
1202	309
1203	1202
1204	1202
1205	1202

Reorganized Rule Number	Prior Rule Number
201	201; 205A; 320
202	202
203	203
204	204
205	302
206	205; 301; 308C
207	206
208	205; 205A
209	207
210	208
211	208
212	209
213	301

214	211
215	214
216	215
217	310
218	312
219	312
220	313B; 401
221	334
222	336
223	308C
301	303
302	302; 303; 305; 305A; 306
303	303
304	303; 605; 1201
305	n/a – new Rule
306	304; 305
307	305
308	303
309	305; 305A; 306; 1202
310	303
311	303
312	n/a – new Rule
313	333
314	216
401	318
402	318A
403	318B
404	307
405	316C; 333
406	305
407	n/a – new Rule
408	317; 604
409	315
410	321
411	317B
412	305; 604
413	309
414	308A
415	322
416	308B
417	326
418	316B
419	341

420	314
421	603
422	801
423	802
424	803
425	804
426	805
427	805; 907
428	327
429	328
430	329
431	330
432	331
433	332
434	319
435	311
436	333
437	n/a – new Rule
501	501; 505
502	502
503	502; 503; 504; 506
504	507
505	511
506	530
507	509; 528
508	511
509	509; 527
510	506; 509; 511; 522; 526; 528
511	508
512	510
513	512
514	516
515	517
516	509
517	531
518	509
519	531
520	532
521	533
522	521
523	522
524	522
525	523

526	524
527	525
528	522
529	529
530	515
601	212; 601
602	602; 603
603	317; 603; 604; 605
604	603; 604
605	210; 305; 603; 605
606	603; 604
607	603
608	603; 604; 605; 805
609	n/a – new Rule
610	604; 606A
611	606B
612	607
613	610
614	608
615	318A; 608; 609
801	324A; 325
802	324B
803	325; 403; 404; 405
804	325; 403; 404
805	324C
806	325
807	325
808	316A
809	325
810	325
811	401; 402; 403; 404; 405
901	901
902	324A
903	317; 604; 805; 912
904	n/a – new Rule
905	907
906	907A
907	323; 902
908	335; 903
909	323; 902
910	904
911	905; 909
912	337; 906

913	340; 905; 909
914	324D
915	910
1201	n/a – new Rule
1202	1203; 1204; 1205
1203	n/a – new Rule

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Research Summary

This appendix contains a review of relevant peer-reviewed research considered the best available science, established wildlife management recommendations, and existing state policies that are referenced in the Statement of Basis and Purpose as support for the proposed Rule 1202 and 1203 changes regarding specific wildlife resources. This appendix is organized by Rule and species. Note that the section headers may not read sequentially due to the fact that only the species for which Rule changes were proposed are included in this appendix, and the appendix is organized by the actual Rule header and species, as shown below.

Rule 1202.c. No Surface Occupancy Habitats

1202.c.(1).A. Columbian sharp-tailed grouse reference summary
1202.c.(1).B. Greater prairie-chicken reference summary
1202.c.(1).C and D. Greater sage-grouse and Gunnison sage-grouse reference summary
1202.c.(1).E. Lesser prairie-chicken reference summary
1202.c.(1).N. and O. Least tern and piping plover production areas reference summary
1202.c. (1).O. Townsend's big-eared bat, Mexican free-tailed bat, and myotis reference summary
1202.c.(1).Q, R, and S. Waters identified by CPW as "Gold Medal," cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters reference summary
1202.c.(1).T. State Wildlife Areas and State Parks

Rule 1202.d. Habitats that Require a Wildlife Mitigation Plan if Oil and Gas Location Density Exceeds 1 per square mile

1202.d.(1)–(4) Bighorn sheep, elk, mule deer and pronghorn reference summary
1202.d.(5) and (8) Greater sage-grouse and Gunnison sage-grouse reference summary
1202.d.(6) and (10) Columbian sharp-tailed grouse and plains sharp-tailed grouse reference summary
1202.d.(7) Greater prairie-chicken reference summary
1202.d.(9) Lesser prairie-chicken reference summary

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Rule 1202.c.

<u>1202.c.(1).A. Columbian sharp-tailed grouse reference summary</u>

Guidelines for the management of Columbian sharp-tailed grouse populations and their habitats
Hoffman et al. 2015, WAFWA Sage and Columbian Sharp-tailed Grouse Technical Committee

Summary: This document was prepared by the Western Association of Fish and Wildlife Agencies (WAFWA) with funding from CPW. Authored by eleven experts on North America's sharp-tailed grouse species, this document seeks to draw from the available peer-reviewed literature and conservation status of Columbian sharp-tailed grouse to provide management guidelines for land managers and regulatory agencies.

Findings:
* Authors recommend to map and validate seasonal habitats of CSTG within areas of potential energy development in order to establish biologically relevant occupancy (NSO) stipulations.
* In the absence of critical seasonal habitat information, standard NSO stipulations are necessary to provide some level of protection surrounding lek sites.
* The most biologically relevant NSO stipulation for CSTG is within 2 km (1.24 miles) of any occupied lek. This figure is based on movements of female CSTG from their lek of capture to nesting and brood-rearing areas.
* Obtaining industry support for an NSO stipulation of 2 km is probably unrealistic. Therefore, NSO stipulations of 0.8-1.0 km (0.5-0.62 miles) are acceptable if restrictions are placed on the density of wells and infrastructure surrounding leks.
* Off-site mitigation should include options for enhancing existing habitats and restoring previously occupied habitats outside of the impacted area.

Columbian sharp-tailed grouse (*Tympanuchus phasianellus columbianus*): a technical conservation assessment
Hoffman and Thomas 2007, USDA Forest Service, Rocky Mountain Region

Summary: This species assessment was prepared for the USDA Forest Service's Rocky Mountain Region in 2007. The report outlines the current status of CSTG in the Rocky Mountain Region, threats to the species and its habitat, and conservation measures to protect against impacts to this species.

Findings:
* Approximately 75 percent of the occupied range of CSTG in Region 2 (including NW Colorado) is designated as having medium to high potential for oil and gas resources.

* Zones of negative influence from oil and gas development may reach over 1 km (0.62 miles) on open ranges and affect the use of habitats that otherwise appear undisturbed.
* Corroboration (metareplication) of results from several different studies on grouse species native to the western US have made it clear that lek abandonment may in fact be related to oil and gas activities.
* There is a threshold for the density of anthropogenic disturbance within CSTG habitat that renders the habitat unusable, but research has not yet determined what that threshold may be specific to CSTG.

Status assessment and conservation plan for Columbian sharp-tailed grouse.
Bart 2000, U.S. Geological Survey, Forest and Rangeland Ecosystem Science Center, Boise, Idaho, USA

Summary: This report was prepared by the U.S. Geological Survey to assess the status of CSTG range wide and explore conservation actions.

Findings:
* The report concludes that CSTG currently inhabit <10% of their historical range in the U.S.
* Colorado contains one of three distinct metapopulations that comprise a majority of the remaining CSTG population.

<u>1202.c.(1).B. Greater prairie chicken reference summary</u>

Effects of management practices on grassland birds: greater prairie chicken
Svedarsky et al. 2003, USGS Northern Prairie Wildlife Research Center, Jamestown, ND

Summary: This report is one in a series of literature syntheses on North American grassland birds. The need for these reports was identified by the Prairie Pothole Joint Venture (PPJV), that recently adopted a new goal, to stabilize or increase populations of declining grassland- and wetland-associated wildlife species in the Prairie Pothole Region. To further that objective, it is essential to understand the habitat needs of birds other than waterfowl, and how management practices affect their habitats. The focus of these reports is on management of breeding habitat, particularly in the northern Great Plains.

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Findings:

***** There is an "area requirement" or territory on the booming ground for males. For 10 territories on expansive grasslands in Kansas, the average size was 518 m^2 (range 100-1060 m^2), with more dominant males holding larger territories (Robel 1966).

* Individual males tend to display on the same lek, or at least in the same general area, in subsequent years (Robel and Ballard 1974). Toepfer (1988) noted that about 82% of the males on a booming ground return from one year to the next, suggesting a high degree of site fidelity of males to a lek.

Greater prairie-chicken attendance at leks and stability of leks in Colorado
Schroeder and Braun 1992, The Wilson Bulletin 104:273284

Summary: A study of greater prairie-chickens on a 300 km^2 grassland in northeastern Colorado to examine lek visitation and lek stability from 1986-1991. Data were collected on lek stability, male lek attendance, and density of leks to better understand male movement behavior and to inform the use of lek and male counts as indices of population status for greater prairie chickens in the region.

Findings:

* Research in northeastern Colorado indicated that about 76% of greater prairie-chicken (*Tympanuchus cupido*) leks were used in consecutive years.

* Leks active each year ranged from 39 to 47 and mean annual turnover rate of leks was 23.8%.

* Of the 80 active leks in the study, 20 leks were active all six years, and a total of 26 leks were active for five of the six years of the study.

* The density of leks was relatively stable at 0.14 leks/km^2

* In Colorado, lek attendance rates of radio-collared male greater prairie-chickens varied seasonally and peaked at 95%.

* Previous research on greater prairie-chickens in Colorado indicated that male birds captured prior to lekking in winter had higher lek attendance rates (97%) than birds captured later near leks (93%).

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Movement and lek visitation by female greater prairie-chickens in relation to predictions of Bradbury's female preference hypothesis of lek evolution
Schroeder 1991, The Auk 108(4):896-903

Summary: The research in northeastern Colorado collected data on 92 female greater prairie chickens equipped with transmitters between 1986 and 1988. Female movement data and nest to lek distances were assessed and used as an indirect measure of home range size.
Findings:
* Females nested an average of 3.62 km from leks where they were first observed; however, females nested an average of 1.00 km from the nearest lek, with distance to the nearest lek ranging from 0.23 to 2.39 km.
* 84.8% of females visit more than one lek in a season, was not related to age of the hen or when they were captured for the study.
* Average diameter for female home ranges in km was 1.51± 0.66 km in early spring and 2.24 ± 1.71 km in late spring.
* Individuals displayed site fidelity to both breeding and winter areas.

Greater prairie-chicken (*Tympanuchus cupido*): a technical conservation assessment
Robb and Schroeder 2005, Prepared for the USDA Forest Service, Rocky Mountain Region - Species Conservation Project.

Summary: A species conservation assessment for greater prairie chicken populations in the Rocky Mountain Region summarizing the scientific knowledge and implication of that knowledge for species management.

Findings:
* The major threats to greater prairie-chicken populations in Region 2 are the loss, fragmentation, and degradation of potential and occupied habitat on both private and public lands, which could occur through inappropriate timing and intensity of livestock grazing, conversion of native prairie for development and crop production, construction of roads, utility corridors, fences, towers, turbines, and energy developments, alteration of fire regimes, and planting of trees.
* Populations in the region are particularly vulnerable to changing land use practices that degrade or eliminate nesting and brood-rearing habitats. In addition, small, localized populations that are isolated from core areas may face greater risk of extinction due to a lack of connectivity.
* Drought can increase the intensity of these impacts.
* Features associated with human development also contribute to habitat fragmentation and introduce disturbance and mortality factors.

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<u>1202.c.(1).C and D. Greater sage-grouse and Gunnison sage-grouse reference summary</u>

Summary of Recovery implementation strategy for Gunnison sage grouse (*Centrocercus minimus*)
U.S. Fish and Wildlife Service. 2020. Upper Colorado Basin Region, Lakewood, Colorado. 75 pages.

Summary: The Recovery Implementation Strategy (RIS) describes how the site-specific, prioritized actions outlined in the Gunnison sage-grouse Recovery Plan will be implemented. The RIS describes "Actions, Activities, and Activity Partners " to identify what needs to be completed and by whom. The document outlines the detailed, on-the-ground, population-specific tactical steps to further the long-term viability and recovery of Gunnison sage-grouse in order to achieve the higher-level recovery actions. The plan includes and identifies a variety of partners who may take lead of any given activity.

Species status assessment report for Gunnison sage grouse (*Centrocercus minimus*). Version 1.0
U.S. Fish and Wildlife Service. 2019. Lakewood, Colorado.

Summary: This Species Status Assessment (SSA) documents an in-depth scientific review of the species' biology and threats with an emphasis on an evaluation of its biological status, and an assessment of the resources and conditions needed to maintain populations over time. This SSA report is intended to help support recovery planning through conservation, and to provide the scientific foundation to make management decisions and to produce future planning documents as needed.

Conservation buffer distance estimates for greater sage-grouse – a review
Manier et al. 2014, U.S. Geological Survey Open-File Report 2014–1239

Summary: This report was prepared by USGS research staff at the request of the U.S. Department of the Interior and is a compilation and summary of published scientific studies that evaluate the influence of anthropogenic activities and infrastructure on greater sage-grouse. The intended purpose was to provide land managers and others a convenient reference when working to develop biologically relevant and socioeconomically practical buffer distances around sage-grouse habitats.

Findings:
* Management recommendations were not made by this report, but interpretations of findings from the relevant scientific literature are provided.
* Six categories of anthropogenic land use and activity were analyzed with respect to distances from greater sage-grouse lek sites.
* Four ranges were interpreted based on the available literature (literature minimum, interpreted range (lower), interpreted range (upper), and the literature maximum).
* Regarding the distance from a lek to the nearest energy development, the four ranges were 2 miles, 3.1 miles, 5 miles, and 12.4 miles, respective to the ranges identified above.
* These values were the distances for observed effects found in the scientific literature.

Summary of science, activities, programs, and policies that influence the rangewide conservation of greater sage-grouse (*Centrocercus urophasianus*)
Manier et al. 2013, U.S. Geological Survey Open-File Report 2013-1098

Summary: This report was prepared cooperatively between the U.S. Geological Survey and the Bureau of Land Management. The report documents and summarizes several decades of work on sage-grouse populations, sagebrush as habitat, and sagebrush community and ecosystem functions based on the recent assessment and findings of the USFWS under consideration of the Endangered Species Act. Though explicit connections to effects on sage-grouse populations are attempted throughout, these connections remain elusive and difficult to document.

Findings:
* Exhaustive summary of GrSG history, social considerations, and literature.
* Overall summary of literature regarding energy development impacts are consistent with other literature reviews included in this list (include much of the same studies).
* Utilized existing oil and gas datasets to analyze impacts to GrSG based on analyses of time-lag effects that indicate a delay of 2-10 years between activity associated with energy development and its measurable effects on lek attendance.

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Sage-grouse and cumulative impacts of energy development
Naugle et al. 2011, Pages 213– 225 in P. L. Krausman and L. K. Harris, editors. Cumulative effects in wildlife management. CRC Press, New York, New York, USA.

Summary: This chapter (4) of the book "Energy Development and Wildlife Conservation in Western North America" was a literature review documenting studies that have investigated the relationships between sage-grouse and energy development.

Findings:
* Fourteen studies reported negative impacts of energy development on sage-grouse, and none reported a positive influence of development on populations or habitats.
* Surface occupancy of oil or gas wells adjacent to leks was negatively associated with male lek attendance in five of seven study areas across Wyoming.
* Leks with at least one oil or gas well within a 0.4 km (0.25 miles) had 35-91% fewer attending males than leks with no well within the same radius.
* Lek attendance at well pad densities of 1.54 well pads per square km was 13-74% lower than attendance at non-impacted leks.

Influences of environmental and anthropogenic features on greater sage-grouse populations, 1997 - 2007
Johnson et al. 2011, Greater Sage-grouse: Ecology and Conservation of a Landscape Species and its habitats. Studies in Avian Biology (vol. 38) University of California Press, Berkley, CA

Summary: Explored the relations between trends of GrSG lek counts from 1997 to 2007 and a variety of natural and anthropogenic features. Lek data was analyzed from all or parts of 14 different states throughout the Sage-Grouse Conservation Area (analogous to historic range). Analyses used the Pearson correlation coefficient between lek count and year as a measure of change in the number of males observed on leks. Trends were examined based on several variables (landscape features).

Findings:
* Trends were correlated with several habitat features, but not always similarly throughout the range.
* Lek trends were positively associated with proportion of sagebrush cover within 5 km and 18 km.
* Trends were lower for leks where a greater proportion of their surrounding habitat had been burned.
* Few leks were located within 5 km (3.1 miles) of developed land, and trends were lower for those leks with more developed land within 5 km or 18km of the lek.

* Active oil or natural gas wells and highways, but not secondary roads, were associated with lower lek count trends.

Yearling greater sage-grouse response to energy development in Wyoming
Holloran et al. 2010, Journal of Wildlife Management 74(1): 65-72

Summary: Used a variety of methods (radio-telemetry, lek counts) and analytical techniques to investigate the response of both male and female yearling sage-grouse to infrastructure in natural gas fields during 2000 to 2005 in the Upper Green River Basin of Wyoming. A total of 17 leks were monitored over the study period and data from 135 radio-telemetered female yearlings and 34 radio-telemetered male yearlings was analyzed.

Findings:
* Leks that recruited more than the expected number of males were significantly farther from energy infrastructure compared to leks that recruited fewer males than expected.
* Leks that recruited more than the expected number of males were, on average, 4.9 - 6.2 km away from the nearest well pad and 4.2 - 4.6 km from the nearest haul road.
* Leks that recruited fewer than the expected number of males were, on average, 1.2 - 1.7 km away from the nearest well pad and 1.7 – 1.8 km from the nearest haul road.
* Yearling males reared in areas with energy infrastructure had significantly lower annual survival (~55%) compared to males reared in areas with limited energy infrastructure (100%).
* Yearling females reared in areas with energy infrastructure had significantly lower annual survival (~69%) compared to females reared in areas with limited energy infrastructure (100%).
* Yearling females avoided nesting within 950 m of energy infrastructure, indicating a functional loss of habitat spanning nearly 700 acres around producing wells.

Greater sage-grouse population response to energy development and habitat loss
Walker et al. 2007, Journal of Wildlife Management 71(8): 2644-2654

Summary: Used lek counts from 2001 to 2005 to assess how coal bed natural gas (CBNG) development and habitat loss influenced sage-grouse populations in the Powder River Basin of NE Wyoming and SE Montana. Conducted two analyses: 1) analyzed lek counts to assess whether trends in male attendance differed between areas with and without CBNG development, and 2) used logistic regression to model lek status (active or inactive) in relation to landscape features hypothesized to influence sage-grouse demographics. Leks were defined as being "in CBNG" (i.e. treatment) if either 1) ≥40% of the area within a 3.2 km radius was considered "developed" by creating 350 m buffers around all well locations and dissolving this development footprint within the 3.2 km lek buffer OR 2) if ≥25% within 3.2 km was considered developed AND ≥1 well was within 350 m of the lek center.

Findings:
* Lek count indices declined by 82% within CBNG fields from 2001 to 2005 (a rate of 35% per year).
* Lek count indices declined by 12% outside CBNG fields from 2001 to 2005 (a rate of 3% per year).
* Among all study leks active in 1997 or later, 38% remained active within CBNG fields while 84% remained active outside of CBNG fields.
* The average time between CBNG development and lek disappearance was ~4 years.
* The top 8 models explaining lek persistence all included a positive interaction with the proportion of sagebrush habitat within 6.4 km of a lek and some variable representing a negative interaction with CBNG development (either proportion of CBNG development within 0.8 km or 3.2 km radii of a lek or the number of years a lek was within CBNG developed areas).
* Found strong evidence that NSO protections within 0.4 km (1/4 mile) were insufficient to prevent lek abandonment over time.

<u>1202.c.(1).E. Lesser prairie chicken reference summary</u>

The Lesser Prairie-Chicken Range-wide Conservation Plan
Van Pelt et al. 2013, Western Association of Fish and Wildlife Agencies, Cheyenne, Wyoming.

Summary: The Lesser Prairie Chicken Range-wide Plan (RWP) was developed by the five lesser prairie-chicken states (Colorado, Kansas, New Mexico, Oklahoma, and Texas), along with oil and gas and electric utility companies, private landowners, and the U.S. Fish and Wildlife Service, as a comprehensive adaptive plan designed to conserve lesser prairie-chickens across the range. Avoidance, minimization, and mitigation actions are primary actions identified and implemented under the RWP. The Conservation Strategy outlined in the RWP has two main objectives: concentrates limited resources for species conservation in the most important areas, allowing for the restoration, enhancement, and maintenance of large blocks of habitat needed by LPC and secondly, identifies areas where development should be avoided, which also helps identify areas where development is of less concern for LPC. This provides developers with the guidance they typically seek for their development planning purposes and helps avoid conflicts over impacts to the species.

Findings:
* RWP avoidance measures include lek surveys in project areas to identify leks and avoidance of habitat loss or fragmentation within focal areas, connectivity zones, and

within 1.25 miles of known leks that have been active at least once within the previous five years.
* Minimization actions include seasonal use restrictions, noise abatement, co-location of facilities, and other best management practices.
* Where avoidance is not possible, the RWP develops a mitigation framework and program.

Location and success of lesser prairie-chicken nests in relation to vegetation and human disturbance
Pitman et al. 2005, Journal of Wildlife Management 69(3):1259-1269

Summary: Female lesser prairie chickens were tracked with VHF transmitters at two study sites to investigate the relationship of nest success and sand-sage and prairie habitat characteristics. Nest success was also examined relative to the locations of well heads, buildings, transmission lines, roads, and center pivot irrigation.

Findings:
* Sagebrush density and diameter was greater at successful nests than unsuccessful nests, and nests sites were positively associated with grass cover, shrub cover, and forb cover.
* Sand-sagebrush habitat around 5 of 6 features (all except unimproved roads) was avoided for 80 m (well heads) to >1000 m (buildings) by nesting lesser prairie-chickens.

Nesting ecology of lesser prairie-chickens in sand sagebrush prairie of southwestern Kansas.
Pitman et al. 2006, Wilson Journal of Ornithology 118:23-35

Summary: Captured and equipped 227 hens with transmitters to study nesting ecology of lesser prairie-chickens in the sand sagebrush ecoregion of southwestern Kansas. Data on age-specific variation in nesting ecology, nest site fidelity in hens, and nest site selection relative to lesser prairie-chickens lek locations are reported.

Findings:
* Apparent nest success was 26 ± 3% and nest success similar for yearlings (31%) and adult (27%) hens and between years of the study.
* The location of 80% of all nests was within 1km of a known lek site, however, 80% of females in the study (147 of 184) nested closer to a lek other than that on which they were captured.
* The authors concluded that providing secure nesting habitat within 1 km of a lek site is an important management strategy.

ATTACHMENT 4

Lesser prairie-chickens of the sand sagebrush prairie
Haukos et al. 2016, in Ecology and Conservation of Lesser Prairie-Chickens, Studies in Avian Biology, Volume 48. CRC Press.

Summary: A detailed analysis of the lesser prairie-chicken in the sand sagebrush prairie ecoregion including population history and trends, ecology of the species, contributing factors to the population decline, as well as conservation priorities and restoration opportunities.

Findings:
* This ecoregion once had the highest density of lesser prairie chickens within their overall range but in 2014 had fewer than 500 birds in just under 16,000 km^2 of potential habitat; long term population goal set in the RWP for the ecoregion is 10,000 birds (0.91 birds per km^2).
* Causes of population decline are loss of habitat through conversion to cultivated crops and other intensive land use, drought, other extreme weather events, and anthropogenic features that influence habitat selection by lesser prairie chickens.
* Reported avoidance distances from lesser prairie chickens' nests to powerlines (1254 m to 1385 m), wells (539 to 588 m), and roads (208 m to 3140 m).
* Desirable ecological conditions for lesser prairie-chickens: connected habitat >5250 km^2, target large, connected sand sagebrush and grassland habitats for conservation and restoration, habitat management centered on areas of sand sagebrush habitat within 3.2 km of a lek should be a high priority to protect nesting habitat in this ecoregion.

Effect of energy development and human activity on the use of sand sagebrush habitat by lesser prairie-chickens in southwestern Kansas.
Robel et al. 2004. Transactions of the North American Wildlife and Natural Resource Conference 69: 251-266

Summary: A six-year study of lesser prairie-chicken decline in southwestern Kansas to assess the extent of the impact anthropogenic features had on lesser prairie-chicken use of available sand sagebrush habitat. Lesser prairie chickens were trapped, equipped with transmitters, and located daily during the nesting season. They used Monte Carlo simulations to determine if any of the six anthropogenic features were related to distances to locations of lesser prairie-chicken nests. Probability distributions were used to determine if nests were significantly ($P = 0.05$) farther than expected from a particular feature and avoidance buffers were created.

Findings:
* Lesser prairie-chicken nests were located farther from five of six anthropogenic features than would be expected at random.
* Mean distance to anthropogenic features avoided by 90% of nesting lesser prairie-chickens was highest for buildings and improved roads, then transmission lines, center-pivot irrigation and well heads. The only non-significant feature was unimproved roads.
* The causative factors were not determined but suggested it could be related to movement and noise output relative to the features.
* Avoidance buffers along roads encompassed 4,990 ha in 1973 and 3,944 ha in 2001. Oil and oil/gas wellheads negatively impacted 583 ha in 1973 and 1,289 ha in 2001. Avoidance buffers around buildings contained 1,229 ha in 1973, increasing to 2,997 ha by 2001. Adult lesser prairie-chicken seldom used sand sagebrush habitat within 693 yards of electric transmission lines, and that avoidance buffer area amounted to 2,679 ha in 2001.
* Combined, the total avoidance buffer areas around anthropogenic features in the three counties reduced the suitability of 63,705 ha and 51,015 ha of sand sagebrush habitat for lesser prairie-chicken nesting in 1973 and 2001, respectively. These areas represent 52% of the sand sagebrush habitat remaining in the three counties in 1973, and 58% of that remaining in 2001

Spatially explicit modeling of lesser prairie-chicken lek density in Texas
Timmer et al. 2014, The Journal of Wildlife Management 78(1):142-152

Summary: estimated lek density in the occupied lesser prairie-chicken range of Texas, USA, and modeled anthropogenic and vegetative landscape features associated with lek density to examine how lek density may respond to changes on the landscape related to an increase in energy development. Anthropogenic features included paved road density, unpaved road density, all road density, density of transmission lines, and active oil/gas pad density.

Findings:
* Lek density increased with an increase in total proportion of grassland and shrubland.
* Lek density was inversely related to active oil and gas well density.
* Paved and unpaved road density was inversely related to lek density.
* Lek density was greatest in areas with higher proportion of shrubs and grasslands and lower densities of paved roads and lower densities of active oil and gas wells.

ATTACHMENT 4

Impacts of energy development on prairie grouse ecology: a research synthesis
Hagen 2010, Transactions of the North American Wildlife and Natural Resources Conference 75: 96-103

Summary: A search of peer-reviewed articles, graduate research theses/dissertations, and non-refereed reports related to prairie grouse and the impacts of energy development. Twenty-two studies (13 peer-refereed, 5 graduate studies and 3 non-refereed reports) that reported quantitative data on prairie grouse responses to energy development.

Findings:
* Hagan evaluated an overall random effects model that included data from all studies that measured distances to anthropogenic features, and the overall model indicated that drawing inference from an average effect size was reasonable (P = 0.43). Anthropogenic features had a negative effect on displacement in all biological seasons for which *d* could be estimated, with the largest effect on nesting season (d = –1.026, 95 percent CI: –1.889, –0.307). The presence of power lines had the largest measurable effect on displacement (d = –1.526, 95 percent CI: –2.052, –0.974), followed by roads (d = –0.736, 95 percent CI: –1.867, –0.126).
* Demographic rates were generally reduced by energy development (d++ = *–0.303,* 95 percent CI: –0.609, –0.064). An examination of *QB* indicated that the effect (d) of anthropogenic features was similar among studies (P = 0.11), species (P = 0.29), features (P = 0.21) and seasons (P = 0.54), for each variable. Demographic rates were lower in developed areas for all biological seasons for which *d* could be estimated, with the largest effect on annual survival (d = –0.523, 95 percent CI: –1.042, –0.250). Buffer areas around natural gas wells and turbines had the largest two effect size estimates, but neither was precise enough to conclude a measurable effect. Only gas fields had a measurable effect on demography of prairie grouse. However, per the *QB* test, drawing inference from the overall random effects model *QT* (P = 0.71) was reasonable and indicated a small to moderate negative effect.
* Based on a meta-analysis, anthropogenic features had a negative effect on displacement in all biological seasons, with the largest effect on nesting season. The presence of power lines had the largest measurable effect on displacement, followed by roads. (Areas around natural gas well and turbines had large effect size estimates, but neither was precise enough to conclude a measurable effect.) The effect of anthropogenic features was similar among studies, species, and seasons.

ATTACHMENT 4

Strategic conservation for lesser prairie-chickens among landscapes of varying anthropogenic influence
Sullins et al. 2019, Biological Conservation 238: 108213

Summary: The authors estimated the distribution of lesser prairie-chicken using data from 170 birds marked with GPS transmitters in Kansas and eastern Colorado between 2013 and 2016. Data was collected at 6 study sites (3 in Kansas and 3 in Colorado) that varied in density of anthropogenic features and species distribution was modeled from the GPS location data and evaluated relative to vegetation and densities of paved and county roads, transmission lines, oil wells, and other vertical features.

Findings:
* Overall, the relative probability of use by lesser prairie-chickens decreased as cumulative densities on anthropogenic features increased.
* Based on the raw probability distribution, the occupancy threshold for vertical point feature densities occurred at ~ 2 vertical features per 12.6 square kilometers (2-km radius). A similar threshold was estimated for oil wells, with areas having more than two oil wells per 12.6 square-kilometers having 8 times lower relative probability of use.
* The model suggested decreased probability of use in 2-km radius landscapes that had greater than two vertical features, two oil wells, 8 km of county roads, and 0.15 km of major roads or transmission lines.
* Predicted probability of use was greatest in 5-km radius landscapes that were 77% grassland.
* Based on predictions, around 10% of the current expected lesser prairie-chicken distribution was available as habitat.
* Broad scale (78.5 km^2) grassland composition and anthropogenic feature densities appear to exert constraints on the distribution of lesser prairie-chickens in the study area.

Balancing energy development and conservation: a method utilizing species distribution models
Jarnevich and Laubhan 2011, Environmental Management 47:926-936

Summary: The study used lek locations from 7 years of survey data in Kansas to examine the distribution of leks relative to environmental factors related to prairie habitat and anthropomorphic factors including highways, oil and gas wells, and electric transmission lines.

Findings:
* Amount of tall grass prairie and grassland were the most influential vegetation factors in lek placement along with lower standard deviation in elevation.

* Anthropomorphic factors had a lower contribution to lek placement compared to habitat variables however leks closer to these features had lower habitat suitability. Distance from oil or gas wells was the most influential anthropogenic feature affecting lek occurrence (for lek locations recorded after 1995) in Kansas and oil or gas well density was the most influential anthropomorphic feature affecting lek occurrence at the largest scale.

Lesser prairie-chicken space use in relation to anthropogenic structures
Plumb et al. 2019, Journal of Wildlife Management 83(1):1216-230

Summary: Conversion of native grassland prairie to row crop agriculture contributes to the decline of lesser prairie chicken however, populations have continued to decline even though this type of land conversion has slowed. This study investigated effects of proximity to anthropogenic structures on home range and nest placement and the effects on space use within home range by tracking 285 radio-collared lesser prairie chickens in the Mixed-Grass Prairie and Short-Grass Prairie ecoregions of Kansas.

Findings:
* Lesser prairie-chickens placed home ranges farther from roads and powerlines than would be expected at random. As distance increased from 0 to 3 km away from roads, the relative probability of home range placement increased 1.54 times. Similarly, as the distance from powerline increased from 0 to 3 km, the relative probability of home range placement increased 1.66 times.
* Distance to oil well did not influence placement of home ranges or nests however, lesser prairie-chickens, on average, used space at greater intensities within their home range farther from wells, during both the breeding and non-breeding seasons.
* Females in south-central Kansas avoided wells during the lekking phase.
* When pooled across regions, lesser prairie-chickens exhibited behavioral avoidance of powerlines, roads, and oil wells within their home range. Lesser prairie-chickens, on average, used space at greater intensities within their home range farther from wells, powerlines, and roads than available.
* Results indicate that avoidance of anthropogenic structures may result in functional habitat loss and continued fragmentation of remaining grassland habitat.
* Predict that well density would be a superior metric to use in future studies when compared to that of distance to well.

Investigation into the decline of populations of the lesser prairie-chicken (*Tympanuchus pallidicinctus*) in southeastern New Mexico
Hunt 2004, Dissertation, Auburn University, Auburn, Alabama, USA.

Summary: The study examined the relationship between oil and gas development and decline in populations of lesser prairie-chickens in southeastern New Mexico by evaluating 41 active leks and 32 abandoned leks relative to the presence of oil wells, roads, and power lines. Abandoned leks had more active wells, more total wells, and greater length of road than active leks, and were more likely than active leks to be near power lines.

Findings:
* Average number of active wells within 1 mile of active leks was 1, while average number of active wells within 1 mile of abandoned leks during their last active year was 8.
* Abandoned leks had an average of 26.7 km (16.0 miles) of road and density of roads of 3.3 km/km^2 (5.1 $miles/miles^2$). Active leks had an average of 20.0 km (12.0 miles) of road and density of roads of 2.4 km/km^2 (3.7 $miles/miles^2$). Abandoned leks had a greater proportion of area within 1.6 km (1 mile) that was within 31 m (100 feet) and 152 m (500 feet) of roads than did active leks.
* Eighteen of 40 abandoned leks (45%) were within 800 m (2,600 feet) of at least one power line, while only 1 of 33 active leks (3%) was near a power line.

Movements and nesting habitat of lesser prairie-chicken hens in Colorado
Giesen 1994, The Southwestern Naturalist, Vol. 39, No. 1: 96-98

Summary: Lesser prairie-chicken hens were trapped on the Comanche National Grassland in southeastern Colorado, outfitted with radio transmitters and tracked during the breeding seasons from 1986-1990. Female movement was recorded and vegetation characteristics were collected for each nest site.

Findings:
* Mean distance from lek-of-capture to nest site ($n = 31$) was 1.80 ± 1.04 km (range 0.20-4.80 km) and was greater ($P < 0.001$) than the mean distance between nests and the nearest lek (1.04 ± 0.60 km, range 0.20-2.50 km).
* Most nests in Colorado ($n = 20$, 69.0%) were beneath shrubs, primarily sand sagebrush ($n = 12$) and small soapweed ($n = 6$), with the remainder in bunchgrasses, primarily sand drop-seed ($n = 5$). The tallest vegetation over nest bowls averaged 50.7 + 14.7 cm (range = 29-81 cm), with 69.0% of nests under vegetation >40 cm in height. Shrub, forb, and grass height, and height-density at nest bowls was greater ($P < 0.001$) then along the paired dependent transects (Table 1).

ATTACHMENT 4

<u>1202.c.(1).N. and O. Least tern and piping plover production areas reference summary</u>

Recovery plan for the Northern Great Plains piping plover (*Charadrius melodus*) in two volumes. Volume 1: Draft breeding recovery plan for the Northern Great Plains piping plover (*Charadrius melodus*) 132 pp and Volume II: Draft revised recovery plan for the wintering range of the Northern Great Plains piping plover (*Charadrius melodus*) and Comprehensive conservation strategy for the piping plover (*Charadrius melodus*) in its coastal migration and wintering range in the continental United States.
U. S. Fish and Wildlife Service 2015, Denver, Colorado. 166 pp.

Summary: Piping plovers breed and raise young on sparsely vegetated sandbars and reservoir shorelines. Changes in the quality and quantity of riverine habitat due primarily to damming water and withdrawals are a primary threat to the species. Habitat destruction and degradation are widespread and have reduced suitable habitat. Human disturbance, predation, and invasive plants further reduce breeding quality and affect survival. Recovery Goal: delisting. Recovery Objective: to restore and maintain a viable population (less than 5% likelihood of extinction in the next 50 years) in the Northern Great Plains by 2035. The Recovery Plan states that “the major threat facing the species on the breeding grounds is a lack of sufficient habitat available frequently enough to support the population at recovery levels.”

Findings:
* The Recovery Plan identifies several Criterion, one of which has the purpose: *To ensure that there is sufficient habitat broadly distributed on the breeding grounds to support a stable population*. Actions for the breeding population include: 1B) Habitat protection, management, restoration, and creation; 2B) Public outreach to minimized human disturbance and promote favorable land management; 3B) Regulatory compliance and certainty**;** 4B) Population trends and reproductive monitoring; 5B) Climate change planning and 6B) Plan evaluation and revision.
* The recovery plan’s focus on habitat protection and enhancement as a major factor in piping plover recovery include maintenance of natural coastal formation processes, actual physical manipulation of the sites, predator control, minimization of human disturbance, and control of off-road vehicle access.
* Oil and gas development is ranked in the high threat category to portions of the breeding population. Issues associated with oil and gas development include large equipment required for seismic surveys, extensive road systems built to access oil wells, powerline strikes, and impacts from continuous industrial sound associated with wells.
* Human disturbance continues to be a threat, particularly on popular river and reservoir reaches where the beaches on which piping plovers’ nest are also attractive

for human recreation. Predation is also a major factor impacting the Northern Great Plains population.

Recovery plan for the interior population of the least tern (*Stern antillarum*)
Sidle and Harrison 1990, U. S. Fish and Wildlife Service.

Summary: This plan outlines recovery strategies to increase the interior population of the least tern to approximately 7,000 birds. Recovery Objective: Delisting. Recovery Criteria: Assure the protection of essential habitat by removal of current threats and habitat enhancement, establish agreed upon management plans, and attain a population of 7000 birds. Actions Needed: 1) Determine population trends and habitat requirements; 2) Protect, enhance and increase populations during breeding; 3) Manage reservoir and river water levels to the benefit of the species; 4) Develop public awareness and implement education programs about the interior least tern; 5) Implement law enforcement actions at nesting areas in conflict with high public use.

Findings:
***** Colorado has known breeding areas at reservoirs in SE Colorado. Relevant specific actions to protect, enhance and increase populations during breeding include: 1) Protect, enhance, and increase populations during the breeding season; 2) Restrict public use within nesting areas and investigate enforcement options; 3) modify or eliminate construction activities that adversely impact reproductive success of interior least terns.
* Because habitat losses are a reason for population declines, protecting and enhancing habitat existing and potential habitat is a major concern. Action: Provide protection and management of breeding habitat.

Piping plover (*Charadrius melodus*) and Interior least tern (*Sterna antillarum*) Recovery Plan.
Slater 1994, Colorado Division of Wildlife, State of Colorado, Department of Natural Resources, Denver, Colorado.

Summary: The Colorado piping plover and least tern recovery plan outlines the species' life histories, as well as reasons for population declines. The CPW recovery plan develops Colorado breeding objectives for downlisting least terns and delisting piping plovers. The management plan includes 1) Management and Acquisition of Habitat, 2) Recreation Management, 3) Depredation Control, 4) Population Monitoring, 5) Domestic Livestock Management, and 6) Information and Education.

Findings:
* Habitat acquisition includes improving administrative and legal control over existing suitable habitat.
* Specifically the plan calls for 1. Continue acquisition of water and water rights to ensure adequate lake levels, providing shoreline nesting and feeding habitat, and prey. 2. Establish long-term control for the purpose of habitat management on Tern Island at Adobe Creek Reservoir via a memorandum of understanding with State Board of Land Commissioners.
* Habitat management includes maintenance of existing suitable habitat and improving potential habitat.

US Fish and Wildlife Service Colorado Biological Services Biological Opinion for Interior Least Tern and Piping Plover for US Army Corps leasing action of John Martin Reservoir to Colorado State Parks
US Fish and Wildlife Service 2001.

Summary: This Biological Opinion is the formal consultation in accordance with Section 7 of the Endangered Species Act on impacts to federally-listed endangered and threatened species associated with a U. S. Army Corps of Engineers lease transferring recreation and surface water management at John Martin Dam and Reservoir Project to Colorado State Parks. The Biological Opinion provides an overview of the recreational and water management lease as well as potential adverse actions to least terns and plovers. It also outlines the conservation measures and management actions required by CPW (Colorado State Parks and Colorado Division of Wildlife).

Findings:
* Actions include: developing a database with nesting locations, education of State Park contractors and visitors regarding least tern and piping plover, weekly monitoring of nests, area closure signage and buoys, training of State Park employees, predator exclusion cases where applicable, vegetation removal, weed control, and a report on nesting activities.

ATTACHMENT 4

Endangered Species Management Plan for Piping Plovers (*Charadrius melodus*) and Interior Least Tern (*Sterna antillarum athalassos*): John Martin Reservoir Project and John Martin State Park, Bent, Co., Colorado *US Army Corps of Engineers 2002.*

Summary: The John Martin endangered species management plan builds upon the 2001 Biological Opinion and describes the project area, collaboration among agencies operating at John Martin and future management for conservation of interior least terns and piping plovers. Actions include weekly monitoring of nests during the spring, establishing a nesting database, completion of an annual report, area closure signage and buoys, as well as education of public, employees, and contractors, and law enforcement. Habitat and population management are outlined in the management plan.

<u>1202.c. (1).O. Townsend's big-eared bat, Mexican free-tailed bat, and myotis reference summary</u>

Guidelines for defining biologically important bat roosts: a case study from Colorado *Neubaum et al. 2017, Journal of Fish and Wildlife Management 8(1):272-282*

Summary: Bat roost conservation is critical to managing bat populations. The paper outlines several criteria for defining biologically important bat roosts to maintain local bat population viability.

Findings:
* To be biologically important, a roost must be hibernaculum, maternity roost, transient roost, colonial bachelor roost, or fall swarming site used by bat species and disturbance or loss of the roost could affect more than 5% of the local population.
* Higher conservation value should be assigned to those roosts occupied by Special Status Species or where large concentrations of bats exceed 20% or more of the local population.

Species conservation assessment and strategy for Townsend's big-eared bat (*Corynorhinus townsendii* and *Corynorhinus townsendii pallescens*). *Pierson et al 1999, Idaho Conservation Effort, Idaho Department of Fish and Game, Boise, Idaho*

Summary: Townsend's big-eared bat conservation strategy details the life history, distribution, threats, and conservation strategy for identification, protection, and conservation of this species.

Findings:
* Townsend's big eared bats demonstrate high site fidelity to roost sites. Identification and conservation of roosting activities is important for the conservation of the species.
* The conservation strategy identifies a conservation action of the elimination of toxic impoundments such as oil and gas reserve pits.
* Identifies buffers for land use and vegetation manipulation changes within .25 miles- 500 feet for timber harvest road building. Seasonal limitations on activities near maternity roosts and winter hibernacula are also recommended.

Colorado Bat Conservation Plan
Navo and Neubaum 2018, 2nd edition, Colorado Committee of the Western Bat Working Group

Summary: The conservation strategy identifies threats, objectives, goals, research needs and recommendations for land and wildlife managers for the conservation of bats in Colorado.

Findings:
* Bat mortalities have been documented at oil and gas locations in Colorado in reserve pits, vent stacks, and other equipment.
* Oil and gas development has the potential for both direct and indirect impacts on bats and bat habitat. Habitat loss, fragmentation, and sensory disturbance from oil and gas development is a concern for bat conservation in Colorado.
* Plan identifies continuing to work with the COGCC on implementing measures to avoid, minimize, and mitigate oil and gas development impacts on bats.

1202.c.(1).Q, R and S. Waters identified by CPW as "Gold Medal," cutthroat trout designated crucial habitat, native fish and other native aquatic species conservation waters, and sportfish management waters reference summary

An Intermittent Stream Supports Extensive Spawning of Large-River Native Fishes
Hooley-Underwood et al. 2019. Transactions of the American Fisheries Society 148:426–441.

Summary: Intermittent or ephemeral streams make up a large percentage of all stream habitats and may have significant roles in spawning, foraging, refugia, and early life history habitat for many fishes. Cottonwood Creek, an intermittent tributary stream in the Gunnison River Basin, was shown to support extensive spawning use.

Findings:

*Cottonwood Creek, an intermittent tributary in the Gunnison River basin, Colorado, was found to be used extensively by spawning Flannelmouth Sucker *Catostomus latipinnis*, Bluehead Sucker *C. discobolus*, and Roundtail Chub *Gila robusta*.
*Large numbers of native fish used the stream each year despite very different flow regimes. The timing of initial fish entry varied by six weeks across three years of study.
*This study revealed use of an intermittent tributary by thousands of native Colorado River fishes, highlighting the importance of nonperennial waters for the completion of the life histories of some large-river fish species.

Headwater Streams & Wetlands are Critical for Sustaining Fish, Fisheries, & Ecosystem Services.
Colvin et al. 2019. Fisheries 44(2):73-91.

Summary: Intermittent or ephemeral streams are part of a larger contingent of headwater streams, which perform biological, geochemical, physical ecological functions, providing habitat and resources for endemic and downstream fishes and aquatic organisms.

Findings:

*Headwater streams and wetlands are integral components of watersheds that are critical for biodiversity, fisheries, ecosystem functions, natural resource-based economies, and human society and culture.
*These and other ecosystem services provided by intact and clean headwater streams and wetlands are critical for a sustainable future.
*Legal protections for these vulnerable ecosystems are necessary to protect water quality, ecosystem functioning, and fish habitat for commercial and recreational fish species.
*Many fish species currently listed as threatened or endangered would face increased risks, and other taxa would become more vulnerable without protections.
*In most regions of the USA, increased pollution and other impacts to headwaters would have negative economic consequences.
*Headwaters and the fishes they sustain have major cultural importance for many segments of U.S. society.

ATTACHMENT 4

A general model of temporary aquatic habitat use: Water phenology as a life history filter
Heim et al. 2019. Fish and Fisheries 20:802–816.

Summary: Fish navigate the transient waters of intertidal zones, floodplains, intermittent and ephemeral streams, lake margins, seasonally frozen lakes and streams, and anthropogenic
aquatic habitats across the globe to access important resources.

Findings:

*All necessary life history functions of fish (spawning, foraging, refuge, and dispersal) can be accomplished in temporary habitats.
*Habitats wet from minutes to months may all be important for different species.
*Temporary habitats can contribute substantially to individual fitness, overall production and important meta-population processes.
*Temporary aquatic habitats are being impacted at an alarming rate by anthropogenic activities
altering their existence, phenology, and connectivity. Scientists, managers and policymakers should consider the role these habitats play in global fish production.

Downstream Movement of Rainbow Trout Fry in a Tributary Sagehen Creek, Under Permanent and Intermittent Flow
Erman and Leidy 1975. Transactions of the American Fisheries Society 104(3):467-473.

Summary:
Rainbow trout fry spawned in an intermittent stream had a diel periodicity in downstream movement that was highly correlated with discharge.

Findings:

*Rainbow trout were found to be spawning in an intermittent stream, occupying it seasonally.
*Shortly after fry emerged in mid-July, the tributary began to dry up and fry began to move downstream, primarily during the day.
*After rains, when the water level remained high without diel fluctuations, few fry were captured.
*When the tributary was permanent, fry exhibited a nocturnal downstream emigration. Many fry remained in the tributary where they were almost the only fish occupants.

ATTACHMENT 4

The Quantitative Importance of an Intermittent Stream in the Spawning of Rainbow Trout
Erman and Hawthorne 1976. Transactions of the American Fisheries Society 105(6), 675–681.

Summary: Foresters and land managers frequently assume that intermittent streams are less important to local salmonid populations than are permanent streams. However, extensive spawning by rainbow trout was found in an intermittent tributary.

Findings:

*An estimated 39-47% of the adult rainbow trout spawned in an intermittent stream while several permanently flowing tributaries attracted only 10-15% of the run.
*Resource managers must be aware of the potential importance of intermittent streams
to local salmonid populations.

Disturbance and Fish Communities in Intermittent Tributaries of a Western Great Plains River
Fausch and Bramblett 1991. Copeia 1991(3):659-674.

Summary: Intermittent canyon tributaries of the Purgatoire River, Colorado, consist of isolated pools during long periods of low or no flow, which are punctuated during summer by intense flash floods lasting one to three days. Despite the frequent strong disturbances and limited opportunities for recolonization, fish were found in most permanent pools sampled along five tributaries.

Findings:

*Of 11 native fishes in the river mainstem, five species penetrated an average of 6.6-9.1 km upstream in four drier tributaries; five others colonized only 0.3-1.0 km upstream; and one species was rare.
*Analysis of fish communities at sites sampled through time in four tributaries indicated that species composition and relative abundances remained relatively constant at three sites with deep complex pools but changed markedly at two sites with shallow simple habitat. This was probably because the latter offered little refuge from floods.
*Relatively variable species composition was found among pools along each tributary, little of which could be accounted for by drought, predation, or habitat complexity alone. Differential effects of unpredictable floods in pools of varying habitat complexity, interacting with recolonization and recruitment, are sufficient to produce the spatial and temporal variation observed in tributary fish communities.

ATTACHMENT 4

A Dynamic Flow Regime Supports an Intact Great Plains Stream Fish Assemblage
Bestgen et al. 2017. Transactions of the American Fisheries Society 146:903–916.

Summary: The perennial Purgatoire River supported all native fishes in the basin, while tributaries supported mainly native fishes that were tolerant of intermittent, harsh habitat.

Findings:

*Persistence of native fishes was unchanged over time in the Piñon Canyon reach of the river even though abundance varied substantially. Despite the presence of upstream Trinidad Reservoir, which reduced flood peak magnitude and frequency and increased base flows, the flow regime of the river remained flashy, with high, turbid, and unpredictable flood flows.

*Peak flows resulted from thunderstorms in tributaries of the Purgatoire River downstream from the reservoir or from snowmelt runoff and usually occurred in August or July. Persistence of the native fish assemblage was related to the magnitude and frequency of peak flows and otherwise harsh habitat, which limit invasion by nonnative fishes from upstream and downstream reservoirs.

*Persistence of the intact native fish assemblage in the Purgatoire River requires maintenance of the dynamic flow regime and prevention of invasions by nonnative fishes.

Additional Resources to Support Aquatic Habitat Buffer Best Management Practices

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1202.c.(1).T. State Wildlife Areas and State Parks

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ATTACHMENT 4

Rule 1202.d.

<u>1202.d.(1) - (4) Bighorn sheep, elk, mule deer and pronghorn reference summary</u>

Human mediated shifts in animal habitat use: Sequential changes in pronghorn use of a natural gas field in Greater Yellowstone
Beckmann et al. 2012, Biological Conservation 147:222-233

Summary: The researchers evaluated fine scale patterns of pronghorn habitat selection between 2005-2009 in the PAPA and Jonah gas fields, using resource selection functions to examine a variety of potential correlative factors that included habitat (slope and plant cover type) as well as oil and gas field development infrastructure and human activity (distance to nearest road and well pad, and amount of habitat loss due to conversion to road or well pad). Overall habitat loss due to road conversion during the study period increased by 12.1% (to 7.6 km^2) in the PAPA gas field, and 20.7% (to 2.5 km^2) in the Jonah gas field. Additional habitat loss due to well pad conversion during the study period increased by 28.7% (to 12.7 km^2) in the PAPA gas field, and 34.1% (to 14.8 km^2) in the Jonah gas field.

Findings:
* Over the study period the authors documented avoidance of areas with high levels of oil and gas field development disturbance, including an 82% decline of use in the number of highest quality habitat patches predicted to be of very high use by pronghorn during winter;
* The authors suggest that the results demonstrate that gas field development is leading to a significant decrease in the number of highest quality habitat patches available to pronghorn in winter and an increase in the number of marginal/poor quality habitat patches available;
* The results show a five-fold sequential decrease in the availability of habitat patches predicted to be of high use and a sequential fine-scale abandonment by pronghorn of areas with the greatest habitat loss and greatest industrial footprint.

Seasonal resource selection and distribution response by elk to development of a natural gas field
Buchanan et al. 2014, Rangeland Ecology & Management 67(4):369-379

Summary: The researchers evaluated elk response to disturbance associated with natural gas development by comparing elk resource selection and distribution pre-development with the same parameters during development in the Fortification Creek Area (FCA) of northeastern Wyoming. Approximately 700 Coal Bed Methane Natural Gas (CBNG) wells and 542 km of collector roads were constructed during the development period (2000-2010). The authors compared elk resource selection and distribution from 1992-1995 with the time period 2008-2010 noting that other habitat and landscape parameters that may influence elk resource selection and distribution did not change during the study periods.

Findings:
* Elk demonstrated behavioral and distribution shifts during development showing increased road avoidance during both summer and winter;
* Summer elk distribution during development showed a 2,459 m avoidance distance from roads – an increase of 1,323 m from pre-development road avoidance;
* Winter elk distribution during development showed a 2,594 m avoidance of distance from roads – an increase of 1,599 m from pre-development road avoidance;
* Elk avoidance behavior resulted in a distribution that mirrored the distribution of development through time;
* In the FCA, elk distribution shifts resulted in approximately 43% and 50% loss of habitat classified as high use during pre-development summer and winter seasons, respectively;
* The authors suggest that mitigation planning focused on reducing the footprint of development, reducing traffic, maintaining visual obstructions (patches of woody vegetation and ridgelines), and retaining undeveloped refugia may help conserve elk populations within developing energy fields.

A literature review of the effects of energy development on ungulates: implications for central and eastern Montana
Hebblewhite 2008, Report prepared for Montana Fish, Wildlife and Parks, Miles City, MT

Summary: Author reviewed 160 scientific and technical reports to summarize the effects of energy development on ungulates, including elk, mule deer, pronghorn, moose, bighorn sheep and woodland caribou. The author recorded study area, methods, results and conclusions for the reports reviewed, and summarized results documenting road avoidance for each species due to previously documented avoidance of roads by ungulates. The author also identified development density thresholds for significant impacts on ungulates, made recommendations for future research, and highlighted management implications of results.

Findings:
* Across studies ungulates demonstrated an average 1131 m avoidance of roads and 1125 m avoidance of well sites;
* Studies reporting well pad densities of 0.49 wells/km^2 (1.25 well/mi^2) or greater identified this development density as having significant impacts on ungulates;
* Studies reporting road densities of 1.05 linear km/km^2 (2.7 linear mi/mi^2) or greater identified this development density as having significant impacts on ungulates;

* Despite these findings, the author notes that the majority energy development studies on ungulates prior to 2008 had been reactive to small-scale rushed regulatory processes and needs, and as a result have been poorly designed and inadequate to proactively identify and address the effects of energy development on ungulates;
* The author notes that the cumulative effects of oil and gas development on habitat probably represent the greatest threat to ungulate populations.

Increases in residential and energy development are associated with reductions in recruitment for a large ungulate
Johnson et al. 2016, Global Change Biology 23(2): 578-591

Summary: Johnson et al. looked at large scale impacts of land use change, including housing development and energy development, over time to look at the effects on mule deer population recruitment in western Colorado. Specifically, they looked at development data from 1980 to 2010 and weather data over time to determine if there was any correlation with declining mule deer fawn:doe ratios, as a metric for recruitment.. Their research objectives were to quantify annual changes in residential development, energy development, and weather conditions within mule deer habitat within mule deer winter ranges and summer ranges and then to test for associations between those annual changes in habitat and weather on annual rates of recruitment. Using linear mixed models, they determined that increasing residential and energy development were correlated with declining recruitment, primarily on winter ranges.

Findings:
* Between 1980 and 2010, there was 37% increase in residential land use within deer DAUs (Data Analysis Units).
* Mule deer winter ranges saw an increase in residential development from 1980 with 23.8% overlap of residential development to 31.2% overlap in 2010.
* Mule deer summer ranges saw less of an increase in overlap with development from 1980 at 14.0% to 19.5% in 2010.
* By 2010, 24% of mule deer winter ranges were affected by development at a buffered distance of 2700m from active wells which was a 56% increase from 1980.
* Seasonal temperature metrics increased over time while seasonal precipitation decreased overtime, other than over winter precipitation which remained average.
* Averaged across all mule deer DAUs there was a decrease in fawn:doe ratios from 65.4 fawns:100 does in 1980 to 50.4 fawns:100 does in 2010.
* They documented that increased residential and energy development on winter ranges had the greatest correlation with declining fawn:doe ratios.
* Residential development had 2X the effect on mule deer recruitment as compared to energy development and weather, with energy development and weather having about equal impact on fawn:doe ratios.

ATTACHMENT 4

Habitat selection by mule deer during migration: effects of landscape structure and natural-gas development AND Migrating mule deer: effects of anthropogenically altered landscapes
Lendrum et al. 2012, Ecosphere 3(9):82; Lendrum et al. 2013, PLOS ONE 8(5): e64548

Summary: Lendrum et al. (2012, 2013) investigated spring migration patterns of adult female mule deer in the Piceance Basin of northwest Colorado from 2008 to 2010. They used GPS collars to address habitat use patterns and factors influencing timing and synchrony of spring migration by comparing areas with ongoing natural gas development activity to areas with little to no development (Lendrum et al. 2012, $n = 167$; Lendrum et al. 2013, $n = 205$). Mean migration distances among study areas varied from 36 to 53 kilometers (distance traveled, 4 winter range study areas), averaging 36 kilometers between seasonal ranges (linear distance; study area range: 32 - 40 km). Well pad densities along migration paths within the two developed study areas were 1.5 to 2.0 pads per square kilometer.

Findings:
* Piceance Basin mule deer demonstrated rapid spring migration exhibiting median durations of three to eight days among areas.
* Stopover use (areas used to increase energy reserves during migration) along migration paths was rare in this area, possibly due to increased deer condition compared to other areas exhibiting common stopover use.
* Migratory mule deer in developed areas migrated more quickly, exhibiting delayed winter range departure and early summer range arrival, and used security cover more than deer from undeveloped areas while avoiding roads, but did not avoid well pads.
* Mule deer in the Piceance Basin appear to avoid negative effects of energy development activity through behavioral shifts in timing and rate of migration.
* Shifts in migration behavior could have consequences for timing of arrival on birthing areas, especially where migration duration is prolonged or occurs at longer distances.
* Enhancing permeability along migration routes by applying dispersed development plans and minimizing disturbance to vegetation that provides security cover should reduce impacts to migratory mule deer.

Energy Development Guidelines for Mule Deer
Lutz et al. 2011, Mule Deer Working Group, Western Association of Fish and Wildlife Agencies, USA.

Summary: This document was developed by the Western Association of Fish and Wildlife agencies to summarize potential impacts of energy development on mule deer and their habitat and in turn provide guidance how to prevent or mitigate those impacts. State wildlife agencies have the responsibility to manage mule deer populations, but federal land management agencies and private landowners manage the habitat, so cooperation and collaboration is necessary to manage habitat and minimize impacts of energy development on mule deer populations. This document identifies issues and concerns with energy development effects on mule deer and provides numerous guidelines to minimize those impacts of oil and gas development, wind energy development, solar energy development and associated roads on mule deer habitat. In addition to guidelines to minimize impacts of development, the document also talks about habitat mitigation options.

Findings:

* Impact thresholds are identified based on the impact of development on habitat and mule deer populations with low impact identified as 1 well pad (not exceeding 20acres)/mi^2, moderate impact being 2-4 well pads (not exceeding 60acres)/mi^2, and high impact being >4 wells pads (>60acres)/mi^2.
* Direct habitat loss is primarily associated with the construction and installation of wells pads, roads, pipelines, and any other associated structures, of which up to 50% of land disturbance can be reclaimed but reestablishing sagebrush is difficult.
* Animals can become physiologically stressed by human activities associated with development like noise and road traffic that can decrease fitness due to increased vigilance, less feeding and resting, which can be especially detrimental in winter when animals are already operating in an energy deficit.
* That associated human activity from vehicle traffic, construction activities, noise of compressor stations and wells can cause animals to avoid habitat in proximity to development up to 1.8 miles away from infrastructure.
* Development can create habitat fragmentation of seasonal habitats that can alter habitat vegetation composition and also make it difficult for mule deer to transition between important seasonal habitats like winter range, migration corridors and fawning areas.
* Secondary effects are also a concern with infrastructure like the increased human activities in an area associated with the development as well as roads provide access for the general public, potential for contamination of soil and water, introduction and spread of noxious weeds, an increased water run-off.
* Key guidelines (not all inclusive):
    -Consult appropriate wildlife and land management agencies at least 2 years prior to submitting project applications to allow time for appropriate studies
    -Design configurations of energy development to avoid or reduce unnecessary disturbances, wildlife conflicts, and habitat impacts.
    -Implement timing restrictions that minimize disturbance or prohibit activities during critical portions of the year.
    -At minimum, construction activities should be suspended from November 15-April 30 on areas designated as critical winter range or in important parturition (fawning) areas from May 1 - June 15.

-Avoid placing facilities in locations that bisect major migration corridors and other important habitats.
-Use existing roads when possible.
-If new roads are needed, close and reclaim unnecessary roads.
-Construct the minimum amount of roads.
-Minimize noise and visibility of infrastructure as much as possible using topography and vegetation.
-Limit traffic during high wildlife use hours (primarily dusk and dawn) especially when animals are concentrated on winter ranges.
-Control noxious weeds

Quantifying spatial habitat loss from hydrocarbon development through assessing habitat selection patterns of mule deer
Northrup et al. 2015, Global Change Biology 21(11):3961-3970

Summary: Research was conducted in the Piceance Basin, Colorado to address 3 questions: 1) how does oil and gas development (roads and wells pads) influence deer habitat selection, 2) do deer respond to development different at night versus day, and 3) at what spatial scale do mule deer most strongly respond to different development features? Data were collected and analyzed from GPS collars over 3 years from 18 deer/yr on winter ranges. Ultimately, they detected impacts to habitat use in the Piceance Basin but the distance from wells was less than documented in other studies in Wyoming where their winter ranges consisted of flat, open sagebrush communities and the Piceance consisted of topographically diverse Pinyon-Juniper communities that provide increased visual cover and sound barriers.

Findings:
* Deer selected open areas and areas further from habitat edges during the night, while during the day they selected treed areas and areas closer to edges.
* Deer selected for steeper slopes and at higher elevations during day and night.
* Deer response to energy development in the Piceance Basin was largely driven by level of human activity and disturbance distances varied by development activity (drilling versus production) and day or night.
* Deer exhibited reduced use of areas within 800m of drilling pads during the night and up to 600m during the day. Increased avoidance during the night may be due to increased disturbance from lights and compressors required for nighttime drilling activity.
* Deer disturbance distances from producing pads was up to 600m during the day, but deer exhibited only weak avoidance of producing pads within 400m at night. Human activity is much lower for producing pads in general and especially at night.
* Deer also avoided other infrastructure like roads primarily during the day.

* Based on deer responses to well pads and roads from energy development, deer behavior was altered within ~50% of critical winter range during the day and ~25% during the night.
* Mitigation options to consider for the drilling phase on mule deer winter range include timing restrictions, staged development, using sound and light barriers, and reductions in human activity/traffic associated with drilling activity.

Reproductive success of mule deer in a natural gas development area AND Mortality of mule deer fawns in a natural gas development area
Peterson et al. 2017, Wildlife Biology 17:wlb.00342; Peterson et al. 2018, Journal of Wildlife Management 82(6):1135-1148

Summary: Peterson et al. (2017) investigated reproductive success, including pregnancy rates (early March) and fetal survival (March until birth), and early fawn survival (0-6 months; Peterson et al. 2018) in developed (0.4-0.9 pads/km^2) and relatively undeveloped landscapes (0.0-0.1 pads/km^2) beginning spring 2012 and continuing through December 2014. They applied statistical models to address reproductive success and a multi-state model to address apparent cause-specific fawn mortality under contrasting energy development scenarios.

Findings:
* Pregnancy and in utero fetal rates (early March; n = 346) were high (0.948, SE = 0.012 and 1.877, SE = 0.029, respectively) and statistically indistinguishable between study areas.
* Fetal survival (n = 383) was lower ($P < 0.05$) in the developed study area during 1 of 3 years (2012) when drought conditions were present, suggesting the combination of severe weather conditions and development activity under observed conditions may influence fetal survival.
* There was no apparent influence from energy development in 0–6 month fawn survival (n = 184) based on similar mortality rates between study areas; mean daily mortality probabilities from predation, malnutrition and unknown causes were similar between areas.
* These results suggest that natural gas development did not exert measurable influence on mule deer pregnancy rates, fetal rates or early fawn survival, but may have negatively influenced fetal survival during 2012 when adult females were exposed to drought conditions during the third trimester.
* These findings are consistent with developed areas in a production phase (little to no drilling activity) exhibiting moderate pad densities (0.4–0.9 pads/km^2), and relationships may differ in areas of higher pad densities and/or drilling activity.
* Developers and wildlife managers should continue to collaborate on development planning, such as implementing habitat treatments to improve forage availability and quality, minimizing

disturbance to hiding and foraging habitat particularly during parturition, and implementing directional drilling to minimize pad disturbance density to increase fetal survival in developed areas.

Across scales pronghorn select sagebrush, avoid fences, and show negative responses to anthropogenic features in winter
Reinking et al. 2019, Ecosphere 10(5):e02722

Summary: Researchers quantified pronghorn resource selection in the Red Desert of SW Wyoming between 2013 and 2016 at both the seasonal home-range scale and patch scale using resource selection functions and step-selection functions. The sample included 142 adult female pronghorn fitted with GPS transmitters.

Findings:
* On average, pronghorn selected areas with increased road and pad densities during summer, but they selected areas farther from wells and with lower road and pad densities during winter;
* Pronghorn selected movement paths that crossed roads during the daytime, but selected paths that avoided roads and night;
* Pronghorn avoided fences in all seasons and at all times of day;
* The authors suggest that restrictions on human activity and energy development during winter, particularly in crucial winter range, would be beneficial for pronghorn populations.

Influence of well pad activity on winter habitat selection patterns of mule deer
Sawyer et al. 2008, The Journal of Wildlife Management 73(7):1052-1061

Summary: Natural gas development creates direct and indirect habitat loss through the installation of roads and wells pads. Researchers examined how 3 types of well pads with varying levels of traffic associated with them affected mule deer habitat selection. They evaluated active drilling well pads, producing well pads with liquid gathering systems (LGS), and producing well pads without LGS. The researchers also evaluated the level of vehicle traffic associated with the different types of well pads. Using 36,699 GPS locations from 31 adult female deer developed resource selection function models to model probability of use as a function of road traffic and other habitat characteristics. Analysis of the data indicated that deer avoided all 3 types of well pads and selected habitat farther from well pads with high levels of activity.

Findings:
* During the winter of 2005-06, mean daily traffic volumes at LGS, non-LGS, and active drill pads were 3.3, 7.3, and 112.4 vehicles per day. During the winter of 2006-

07 mean daily traffic volumes at LGS, non-LGS, and active drill pads were 3.6, 8.4, and 85.3 vehicle detections per day.
* Based on 24,955 locations from 20 GPS collared deer during the 2005-06 winter, most deer selected higher elevations, moderate slopes, and away from all well types.
* Based on 11,744 locations from 11 GPS collared deer during the winter of 2006-07, most deer again selected higher elevations, moderate slopes and non-LGS, active well pads, and LGS wells.
* Models from both years showed deer selected habitats farther away from well pads with the greatest activity, so they used habitats closer to LGS pads, but farther away from non-LGS pads and active drilling pads that had the most traffic volume.
* Their models indicated that while there was still an avoidance of LGS wells, there was a 38-63% decrease in loss of habitat associated with the LGS pads that had the lowest traffic volume compared to the non-LGS and active well pads.
* Indirect habitat loss was greatest at the active drilling pads, however, those are short term activity (6months - 2 years) as opposed to the long term indirect habitat loss of the producing pads.
* Their results suggested that reducing traffic from 7 to 8 vehicle passes per day for non-LGS pads to the 3 vehicles per day for the LGS well pads was sufficient for mule deer to perceive less risk and not avoid the LGS pads as much as the non-LGS pads.
* Their results showed that waiving winter drilling restrictions disturbance to mule deer increases and indirect habitat loss may increase greater than 2 times than with drilling restrictions.
* They indicated that by installing liquid gathering systems they were able to lessen indirect habitat loss.

A framework for understanding semi-permeable barrier effects on migratory ungulates
Sawyer et al. 2013, Journal of Applied Ecology 50:68-78

Summary: Impermeable barriers to migration greatly limit how, when and if animals will continue migrating, however, many forms of development (including roads and wells pads) are semi-permeable depending on their density on the landscape. Researchers developed a project to quantify potential barriers and thresholds, to identify and measure behavioral responses to semi-permeable layers, and to consider characteristics of the migration landscape and how the benefits of migration might be reduced by behavioral changes. GPS data was collected from deer in 2 different winter range areas, Dry Cow Creek and Wild Horse Range, within the Atlantic Rim Project Area in South-central Wyoming before development (Phase I) and during development (Phase II). Ultimately, they found that increased levels of gas development in migration routes may force deer to detour, move faster, reduce stop-over in quality forage areas, reduce the amount of deer use and constrict the migration corridor.

ATTACHMENT 4

Findings:
* Coalbed methane operations developed more extensive and dense in the Dry Cow Creek winter range area with road and well densities increasing from .56 km/km^2 and .77km^2 to 1.92km/km^2 and 2.82km^2. The Wild Horse Range winter range experienced lower development with roads and well densities increasing from .83 km/km^2 and .65 km^2 to 1.51 $km/km^2$and 1.86 km^2.
* Movement rates during migration increased for deer in the Dry Cow Creek development from 1.06 km/hr to 1.94 km/hr, but then decreased after they passed through the development area at a greater rate with development from 1.25 during Phase I to .21km/hr during Phase II.
* Some animals in the Dry Cow Creek development that experienced both phases of development did alter their route from previous years by moving around the boundary of the development but then rejoining their traditional route 3-4km beyond the development bypassing approximately 8km of their traditional route.
* Overall, deer use decreased by 10% and 50% in split phases of the Dry Cow Creek development.
* In contrast, no significant changes to migration movement of deer were detected in the Wild Horse Basin development area with less extensive development.
* Deer in the Dry Cow Creek used less stopover habitat as development increased.
* Deer in the Wild Horse Basin used the same amount of stopover habitat pre and post development.
* Ultimately, mule deer use in the more extensively developed migration corridors decreased by 53% and movement rates nearly doubled as development increased.
* Timing stipulations were implemented in the Wild Horse Basin from November 1 to April 30th and may have mitigated some of the effects to migration movements and use.
* Results suggest that when animals move more quickly through developed areas they slow down outside the development area to try to catch up with vegetation phenology to get the most nutritious vegetation.

Mule deer and energy development—Long-term trends of habituation and abundance
Sawyer et al. 2017, Global Change Biology 23(11):4521-4529

Summary: Researchers evaluated the long-term effects of gas development on mule deer populations on the Pinedale Anticline, WY using telemetry data from 187 individual deer over a 17-year period, including two years of predevelopment monitoring and then the rest was when the gas development was occurring. The purpose of the study was to determine if deer habituated to the development activity over time as gas drilling and road development increased. They measured direct habitat loss from development for well pads and roads. They measured habituation as the average proximity to well infrastructure during the 15-year development phase. Researchers also estimated deer abundance throughout the study and made comparisons to WY Game and Fish data on the entire Sublette County deer herd which included the study area.

Findings:

* Ultimately, they found that deer did not habituate to the activity and infrastructure associate with gas development and deer stayed an average of 913 m further from well pads compared to before development and during the last 3 years were actually 1.38 km further from wells pads then predevelopment.
* The study area consisted of ~264 km^2 of mule deer winter range characterized by high elevation sagebrush and sagebrush-grasslands of which 3.5% (9.5 km^2) was loss to well pads and roads.
* The deer population in the study area declined by 36% over the 15-year development phase while the great Sublette deer herd declined by only 16%, which was probably largely based on the Pinedale anticline deer population decrease.
* They did find that mule deer response to well pads was inversely related to winter severity; essentially during severe winters, deer avoidance of wells decreased as animals in poorer condition are less risk averse to meet nutritional demands where animals in good condition can afford to be more risk averse.
* Deer stayed away from well pads by 2,418 meters during mild years, 2,118 meters during average winters and only 1,858 meters away during severe winters.
* Onsite mitigation of installation of pipelines for liquid gathering to reduce truck traffic, drilling of multiple wells (up to 24) per pad, and creating a fund for fence modification, water developments, conservation easements, and other projects probably reduced human disturbance, habitat loss, and lessened deer avoidance, but it did not completely mitigate effects.

Long-term effects of energy development on winter distribution and residency of pronghorn in the Greater Yellowstone Ecosystem
Sawyer et al. 2019, Conservation Science and Practice 1(9):e83

Summary: The researchers investigated oil and gas development avoidance, displacement, and winter residency patterns of pronghorn in the southern Greater Yellowstone Ecosystem (Wyoming) by monitoring 171 collared individual pronghorn from 2005-2017 in a developing gas field. The study area comprised 550 km^2 of the northern half of the Pinedale Anticline Project Area – the largest natural gas field in the Greater Yellowstone area. BLM initially approved 700 well pads, 645 km of pipelines, and 444 km of access roads in July 2000. An additional 4,400 wells were approved for development in 2008. The footprint of active wells, access roads and other infrastructure expanded annually over the study period.

Findings:

* Predicted pronghorn distance from the nearest Oil and Gas Location increased from 908m in 2005 to 1,708m in 2017;

* Pronghorn avoidance of Oil and Gas Locations appeared intermittent until 2011, after which they switched to consistent avoidance and regularly used areas increasingly distant from Oil and Gas Locations. This finding suggests a development threshold was exceeded and altered pronghorn behavior;
***** During the study period (2005-2017) the amount of time pronghorn spent in the 550km^2 study area during decreased by 22%, and the proportion of pronghorn leaving the study area increased by 57%.
* The authors suggest that the diminishing winter residency rates in the study area on traditional winter range most likely reflects a lowered carrying capacity. The authors reference Wyoming Game and Fish Department population estimates suggesting a herd-level decline of 47% between 2005 and 2017, but they acknowledge the difficulty in directly translating reduced winter residency rates to demographic responses.

Migratory disturbance thresholds with mule deer and energy development
Sawyer et al. 2020, The Journal of Wildlife Management 84(5):930-937

Summary: As GPS data has become more available the location and importance of mule deer migration routes have been identified. For this study, the goal was to examine how or if natural gas development influenced mule deer behavior during migration in open sagebrush habitats. Researchers used GPS data form 56 deer across 15 years to determine how natural gas development can impact migration. Impacts to migration routes were evaluated by assessing habitat selection of mule deer to determine if there was any threshold where migratory use would decline at the study area scale, migratory route scale, and individual movement scale. Traditionally, these kinds of analyses used well density as the metric of development intensity when well pads covered small, similar acreages of land, however, for this study they chose to look at surface disturbance as well pads now vary from 0.5 ha – 16 ha in the study area. Overall, migratory use by mule deer declined as surface disturbance increased.

Findings:
* Regardless of spatial scale, declines in mule deer migratory use occurred when surface disturbance exceeded 3%.
* This indicates that low level of surface disturbance is tolerable up to the 3% threshold through short segments of deer migration routes.
* Disturbance area and juxtaposition needs to be considered, so fewer larger blocks are probably less impactful than more, smaller blocks.
* Their study was narrow, so deer could see safe habitat going through the area, however, larger disturbance areas across longer lengths of migration routes may be more impactful.

* Vegetation type should also be a consideration of impact, as open sagebrush habitats with development may be more impactful than areas with tall vegetation that may provide visual protection from disturbance.
* They recommended adopting conservation practices like sage-grouse where management is focused on minimizing surface disturbance in critical habitats.
* Researchers reported that they highlighted the possibility that semi-permeable barriers have the potential to reduce the value of migration if they are not getting the best forage, experience higher activity, and potentially higher predation.
* They also report that ungulates that have a high fidelity to narrow, linear pathways may be more vulnerable to barrier effects than more nomadic migrants.

Identifying impediments to long-distance mammal migrations
Seidler et al. 2014, Conservation Biology 29(1): 99-109

Summary: Researchers applied Brownian bridge movement models and resource utilization functions to assess threats to pronghorn migration and identify migratory stopover sites associated with anthropogenic development in the Upper Green River Basin, Wyoming, including both the Pinedale Anticline Project Area (PAPA) and Jonah gas fields.

Findings:
* In all years of the study (2005-2009) probability of pronghorn use during migration was high outside of the areas of densest gas field development and low inside the areas of densest gas field development;
* Pronghorn reduced their migratory use of the most intensively developed areas of both the PAPA and Jonah fields, consistent with the reduced winter use patterns identified by Beckmann et al. (2012) for the same area;
* Although pronghorn exhibited low use within the developed gas fields, they exhibited high use and stopover sites in still-undeveloped areas and areas directly outside the more densely developed areas. The authors suggest that this indicated: 1) that pronghorn found sufficient resources in adjacent areas to warrant stopovers in alternate locations, 2) that pronghorn selected stopovers outside of gas fields due to perception of migratory impediments, or both.

Analysis of habitat fragmentation of oil and gas development and its impact on wildlife: a fragmentation for public land management planning
Wilbert et al., 2008 The Wilderness Society

Summary: The authors presented a methodology and analytical framework for evaluating habitat fragmentation associated with oil and gas development. A spatial GIS analysis was presented that examined direct, indirect and cumulative impacts to wildlife from different oil and gas development alternatives based on well pad density. The analysis included hypothetical simulations with varying well pad densities and correlated road network requirements for pad access at varying pad densities. The analysis also quantified habitat fragmentation and functional habitat loss at varying pad densities based on known displacement distances for various wildlife species.

Findings:
* A well pad density of 1 pad per square mile correlated with a mean road density of ~ 1 linear mile per square mile;
* The rate of change in terms of necessary increases in road density and habitat fragmentation was much higher as development increased from 1 well pad per section to 5 well pads per section than it was for development increases beyond 5 well pads per section;
* Based on the mean distance to nearest road calculated for varying well densities, and the known displacement distances presented for ungulates and grouse species, the authors present a compelling case that indirect impacts to these species groups increase dramatically beyond a well pad density of 1 per square mile and are extreme at well pad densities beyond 5 per square mile.

Recommendations for Development of Oil and Gas Resources within Important Wildlife Habitats
Wyoming Game and Fish Department 2010, Cheyenne, Wyoming, Version 6.0, Revised April 2010.

Summary: Wyoming Game and Fish Department (WGFD) summary of thresholds of oil and gas development and related activities that impair the functions or suitability of important wildlife habitats, including planning and management recommendations to avoid or minimize impacts as oil and gas developments reach identified thresholds, and mitigation recommendations to offset or compensate unavoidable adverse effects as thresholds are exceeded.

Findings:
* Mule Deer and Pronghorn - WGFD concluded that for mule deer and pronghorn crucial winter range an Oil and Gas Location density of 1 per square mile (or up to 20 acres of disturbance) causes a moderate impact and a density of 2-4 per square mile causes a high impact. The impact is extreme when densities exceed 4 per square mile. WGFD recommends that well field developments not exceed a density of 1 Oil and Gas Location per square mile within mule deer and pronghorn crucial winter range because it is unlikely that habitat effectiveness can be maintained at higher densities.
* Elk – WGFD concluded that elk are sufficiently sensitive that any level of development within crucial winter ranges or production areas cause more than a "moderate" impact, and a density of 1-4 Oil and Gas Locations or up to 60 acres of

disturbance pads causes high impact. WGFD strongly discourages this level of development within these elk habitats.
* Bighorn sheep – WGFD notes that bighorn sheep are more susceptible to disturbance-related stress than are most other ungulates (MacArthur et al. 1982). Elevated stress levels in sheep have been linked to depressed immune response, loss of condition, reduced lamb survival, and elevated mortality rates. In addition, distributions of bighorn sheep crucial winter ranges and production areas are very restricted and generally do not coincide with locations of high oil and gas potential. For these reasons, WGFD recommends "no surface occupancy" within bighorn sheep crucial winter ranges and production areas.
* Big Game Migration Corridors – WGFD recommends NSO within narrow migration corridors or "bottlenecks" of less than 0.5 mi width (Sawyer et al. 2005, 2006, 2008). Within migration corridors that exceed 0.5 mi width, the recommended management prescription is to maintain options for animal movement along the corridor and avoid further constricting the corridor such that a bottleneck is created. Well field developments should not exceed 4 well pad locations or 60 acres of disturbance per square mile. Fences, expansive field developments, and other potential impediments to migration should not be constructed.
* In order to minimize direct and indirect effects WGFD recommends the following additional management and mitigation practices for well field developments:
  · Seasonal timing limitations on drilling operations and related activities to avoid the highest use periods;
  · Design and implementation of habitat treatments on- or off-site to maintain habitat function and offset the loss of habitat effectiveness throughout the areas directly and indirectly affected by each well location. Voluntary contribution to a mitigation trust account is an option if the operator cannot fund and implement a habitat improvement project.

1202.d.(5) and (8) Greater sage-grouse and Gunnison sage-grouse reference summary

Greater sage-grouse response to the physical footprint of energy development
Kirol et al. 2020, The Journal of Wildlife Management 84(5):989-1001

Summary: Investigated the relationship between the physical footprint of energy development on greater sage-grouse nest and brood survival. Analyses were based upon the amount of surface disturbance that female sage-grouse were exposed to during reproductive stages. From 2008 to 2014, data was collected in 6 study areas in Wyoming, containing 4 primary types of renewable and nonrenewable energy development. The focus was on "press disturbance" (i.e. disturbance sustained after initial disturbance and associated with existing energy infrastructure and human activity).

Findings:
* Exposure to press disturbance during nesting and brood-rearing was related to lower nest and brood survival.
* Lower nest and brood survival manifested at different spatial scales, with the likelihood of a successful nest being negatively associated with the amount of press disturbance within an 8-km^2 (3.1-mi^2) area.
* Broods exposed to any press disturbance within a 1-km^2 area were less likely to survive compared to broods not exposed to press disturbance.
* Greater than 90% of nest and brood-rearing locations were in habitat with <3% press disturbance within a 2.7-km^2 (1.0 mi^2) area.
* Results fill void in literature for demographic responses to energy development, and links surface disturbance associated with energy development to reproductive costs for female greater sage-grouse.

Quantifying habitat loss and modification from recent expansion of energy infrastructure in an isolated, peripheral greater sage-grouse population
Walker et al. 2020, Journal of Environmental Management Vol. 255 Online Publication

Summary: This study mapped the annual distribution, surface type, and activity level of energy and non-energy infrastructure in the Parachute-Piceance-Roan (PPR), a small, peripheral greater sage-grouse population in Colorado with expanding oil and gas development, from 2005 to 2015.

Findings:
* From 2005 to 2015 the footprint of energy infrastructure more than doubled.
* The three land cover classes most affected by energy infrastructure were also those strongly selected by greater sage-grouse.
* Topographic constraints appear to concentrate energy infrastructure in areas with gentler topography that also have the highest GrSG use.
* Greater sage-grouse selected areas with lower levels of anthropogenic disturbance during the winter and breeding seasons, but appear to tolerate higher levels of disturbance during the summer-fall seasons.

Investigating impacts of oil and gas development on greater sage-grouse
Green et al. 2017, The Journal of Wildlife Management 81(1): 46-57

Summary: Investigated the impacts of oil and gas development and environmental and habitat conditions (sagebrush cover and precipitation) on changes in male sage-grouse lek attendance in Wyoming from 1984 to 2008. Objectives were to evaluate the impact of oil and gas development on changes in lek attendance while accounting for habitat and environmental covariates. Also explored whether lek attendance exhibited delayed responses to time-varying covariates (lag times). Authors used lek count data from 1980 to 2008 for 614 active leks statewide. The parameter of interest was the change in lek attendance across years rather than the counts themselves. Included two measures of oil and gas development: 1) well density (wells/sq km) and 2) disturbance area of well pads (sq km) and five spatial scales around the lek: 800m, 1,600m, 3,200m, 5,000m, and 6,400m.

Findings:
* Models including well density within 6,400m at various time lags performed the best in each model set, and a 4-year lag on well density was the best model for 4 of the 5 spatial scales.
* Changes in lek attendance relative to sagebrush cover were effectively zero.
* There were no obvious patterns in models including precipitation covariates across time lags or spatial scales.
* Models including well density performed the best among all combinations, with 10 of the top 11 models including well density.
* On average, lek attendance was stable when no oil and gas development was present within 6,400m
* A well pad density of 0.39/sq km (1 per sq mile) corresponded to a decline of approximately 1.4%/year. However, declines in lek attendance did not become significant until well density reached approximately 4 wells/sq km, and at that well density a decline of almost 14%/year was expected.

Mitigation effectiveness for improving nesting success of greater sage-grouse influenced by energy development
Kirol et al. 2015, Wildlife Biology 21(2): 98-109

Summary: Primary objective was "to determine if adaptive oil and gas development practices can mitigate negative effects of development on sage-grouse nesting success." Specific questions being asked were 1) does sage-grouse nest survival differ in mitigated, non-mitigated natural gas development habitats, and habitats not altered by natural gas development, and 2) what infrastructure features most influence observed differences in nest survival. Study took place in the Powder River Basin of Wyoming from 2008-2011 with a total of 301 nests used to estimate nest success. "Mitigated" natural gas development areas included those areas where attempts were made to 1) reduce vehicle traffic and road construction, 2) minimize overhead power lines, 3) use of liquid gathering systems to reduce or eliminate the need for on-site reservoirs to store produced water, and 4) reduced overall facility footprints/disturbance.

Findings:
* When habitat variables were accounted for, implementation of mitigation strategies improved nest survival by approximately 5% over non-mitigated areas, but nests in mitigated areas still had a 5% lower survival rate than unaltered habitat.
* Nest survival for unaltered habitat = 64%, Nest survival for mitigated development = 59%, Nest survival for non-mitigated development = 54%.
* The amount of water edge (represented by a small number of natural water bodies but largely driven by produced water reservoirs) within 1.3km of a nest site was the most strongly supported predictor variable of nest survival. There was a significant negative association between nest survival and water edge.
* Also, found that mitigation focused on reducing sagebrush removal was important to bolstering nest survival.

Winter habitat use of greater sage-grouse relative to activity levels at natural gas well pads
Holloran et al. 2015, The Journal of Wildlife Management 79(4): 630-640

Summary: Investigated sage-grouse use of wintering habitats relative to distances to infrastructure, densities of infrastructure, and activity levels associated with infrastructure of a natural gas field in southwestern Wyoming. Study was conducted on the northern half of the Pinedale Anticline Project Area during the winters of 2005-2006 to 2009-2010. Monitored sage-grouse winter habitat use annually between 15 November and 15 March using 20 data logger stations spaced throughout the study area, 10 in the vicinity of natural gas infrastructure and 10 outside the vicinity of natural gas infrastructure. The response variable was a visit to a logger station-monitored area by a VHF transmitter equipped sage-grouse. Analysis looked at conventional well pads (where liquids were stored on-site and removed via tanker truck) and LGS well pads (where liquids were gathered/piped off-site thereby reducing daily traffic volumes to well pads) separately.

Findings:
* Well pad density was a better predictor of both the total number of sage-grouse and total number of log events (number of times an individual grouse visited a location) than was distance to well pads. As the number of well pads within 2.8 km (1.74 miles) of a data logger station increased, the number of sage-grouse and the number of log events decreased.
* At the individual level (amount of time an individual spent in a particular area) sage-grouse consistently avoided areas close to conventional well pads. Avoidance of LGS pads as well as avoidance of plowed haul roads was inconsistent.
* Also found that the relative probability of a location being used by sage-grouse and the amount of time sage-grouse spent in an area were positively related to sagebrush height.

* Authors suggest that reducing well pad densities within a developed energy field represents a potential on-site option for reducing the effects of energy development on wintering sage-grouse.

Spatial heterogeneity in response of male greater sage-grouse lek attendance to energy development
Gregory and Beck 2014, PLOS One 9(6):e97132

Summary: Primary objective was to "explore the possibility of spatially varying relationships among oil and gas development density and sage-grouse lek attendance" in Wyoming. Secondary objective was to "investigate the possibility of similar development densities resulting in opposite trends in sage-grouse lek attendance." Also evaluated the effects of past well-pad densities on current sage-grouse lek count response to oil/gas development to assess lag effects. A total of 814 leks with data from 2002 to 2011 were included in the analysis.

Findings:
* Analysis indicated that a 4- to 5-year lag occurs between the time oil/gas development reaches a particular density to when population-level sage-grouse responses are observed.
* Observed significant declines (23.8%) in male lek attendance at oil/gas development densities of >0.7 well-pads/km sq (0.27 well pads per square mile) within a 10km x 10km assessment window. However, spatial analysis suggests that the rate of loss was not uniform across the state.

Prioritizing winter habitat quality for greater sage-grouse in a landscape influenced by energy development
Smith et al. 2014, Ecosphere 5(2):1-20

Summary: Study sought to understand the suite of ecological conditions of winter habitats that are most critical to sage-grouse population persistence within a developing oil and natural gas field in south-central Wyoming and northwest Colorado. Specific objectives were to: 1) develop winter resource selection and habitat-specific survival models for female sage-grouse, 2) evaluate the relative influence of environmental characteristics and anthropogenic features on winter habitat selection and survival of female sage-grouse, and 3) map habitat quality to identify areas of conservation importance. Data included 537 locations from 105 female sage-grouse collected between November 1 and March 15 2007 – 2010.

Findings:
* Anthropogenic variables associated with improved model fit for winter use locations included surface disturbance and the number of wells within a 0.5 km radius

scale. However, surface disturbance in general (which included both energy infrastructure and human dwellings) was more strongly supported than number of wells.
* The relative probability of occurrence (winter use) decreased by ~3.3% for every 1% increase in surface disturbance within a 0.5 km radius.
* Overwinter survival averaged 91% (range 84 to 96%) and there was no association between anthropogenic variables and survival.
* Results showed that sage-grouse avoidance of surface disturbance due to oil/gas development resulted in indirect loss of otherwise suitable winter habitat. However, there was no link between oil/gas development and female winter survival.

Greater sage-grouse (*Centrocercus urophasianus*) select habitat based on avian predators, landscape composition, and anthropogenic features
Dinkins et al. 2014, The Condor 116(1): 629-642

Summary: Compared landscape attributes, anthropogenic features, and densities of avian predators among 792 sage-grouse locations (including 340 nests, 331 early brood, and 121 late brood) and 660 random locations in southwestern and south-central Wyoming using multinomial logistic regression. Anthropogenic features included oil and gas structures, communication towers, power lines, roads, and rural houses. Oil and gas structures included wells, compressor stations, transfer stations, refineries, and other related buildings – they were quantified as number per square kilometer.

Findings:
* Nesting, early brood, and late-brood sage-grouse selected areas with lower oil/gas structure density compared to random locations. Results were significant for early-brood vs. random and for late brood vs. random but not for nest vs. random.
* Sage-grouse use was also negatively associated with density of major roads and density of power lines.
* Sage-grouse used areas of flatter topography compared with random locations.
* The top model discriminating sage-grouse use locations compared to random locations included parameters of all three covariate sets modeled: avian predator density, anthropogenic feature density, and landscape attributes.
* Overall, study found that sage-grouse selected locations farther away from landscape attributes that could be used as perches or provide food subsidies to avian predators, including oil and gas structures, at all reproductive stages.

ATTACHMENT 4

Disturbance factors influencing greater sage-grouse lek abandonment in north-central Wyoming
Hess and Beck 2012, Journal of Wildlife Management 76(8): 1625-1634

Summary: Evaluated lek abandonment at 183 leks (144 occupied, 39 unoccupied) from 1980 to 2009 in the Bighorn Basin in north-central Wyoming. Used a variety of landscape predictor variables including agriculture, oil/gas development, prescribed fire, wildfire, roads, and vegetation to determine how these factors may have influenced lek abandonment using logistic regression. Used nested circular analyses at 1.0, 3.2, 4.0, 5.0, and 6.4 km radii around leks to test effects of scale.

Findings:
* The top model include both anthropogenic and environmental characteristics, including 1) number of oil wells within 1.0 km radius of leks, 2) percent wildfire within 1.0 km radius, and 3) variability in shrub height within 1.0 km radius.
* The number of oil/gas wells within 1.0 km radius of leks and variation in shrub height within 1.0 km radius of leks were the two most influential predictor variables on lek abandonment.
* The odds of lek abandonment increased by 34% with each additional well within 1.0 km radius of a lek.

Experimental evidence for the effects of chronic anthropogenic noise on abundance of greater sage-grouse at leks
Blickley et al. 2012, Conservation Biology 26(3): 461-471

Summary: Tested the hypothesis that lek attendance (both male and female) is negatively affected by both chronic intermittent and continuous noise from energy development by conducting noise playback experiments in a population relatively unaffected by human activity. Study conducted over 3 breeding seasons in Fremont County, WY from 2006-2008. Paired treatment (n=8) and control (n=8) leks on the basis of similarity in previous male attendance and geographic location. Used linear mixed –effect models to assess relation between covariates and the proportional difference in annual and within-season peak attendance and baseline attendance. Both drilling (continuous) and road (intermittent) noise was played at 70dB(F) measured 16m in front of speakers at leks, similar to noise levels measured ~400m from drilling rigs and main access roads in Pinedale, WY.

Findings:
* Peak male attendance relative to baseline levels was lower on treatment leks than paired control leks, and the decrease was larger at road noise leks (73% decrease compared with controls) than at drilling noise leks (29% decrease).
* Effects of noise occurred in the first year of the study and were observed throughout the experiment.

* Female attendance at leks treated with noise was lower than that on control leks, however both the null model and the model including noise were both highly supported, providing only moderate support for the effects of noise.

A currency for offsetting energy development impacts: horse-trading sage-grouse on the open market
Doherty et al. 2010, PLoS ONE 5(4): 1-9

Summary: Tested the hypothesis that lek abundance and persistence are a process of well density when compared to control populations outside of areas developed for energy. Used a database of active (n=1,190) and inactive (n=154) leks from throughout Wyoming with data from 1997 to 2007. Used number of wells within 3.2km radius of a lek to classify each lek into one of five categories of energy development: 1) no wells within 3.2km, 2) up to 12 wells, 3) 13-39 wells, 4) 40 to 100 wells, 5) 101 to 199 wells. Used logistic regression to analyze lek persistence and spline regression to analyze abundance of males at leks relative to different development thresholds. Analyzed WAFWA GRSG Management Zones I (Great Plains) and II (Wyoming Basins) separately. Although this study was conducted in Wyoming, Colorado also falls within Management Zone II, due to similar habitat and other environmental conditions.

Findings:
* In all analyses, the probability of lek persistence and abundance of males on leks declined with an increase in well density.
* Well densities of 1 to 12 wells within 3.2km radius of a lek (well densities up to 1 pad per 640ac) represented a level of development within which impacts were indiscernible. Beyond this threshold, lek abandonment and declines in birds at remaining leks increased.
* Well densities of 13-39 wells within 3.2km of a lek (up to 1 pad per 160ac) doubled the likelihood of lek loss (abandonment) across study areas; and well densities of 40-100 wells within 3.2km (up to 1 pad per 80ac) increased likelihood of lek loss by 5.1 in Management Zone I and 2.8 in Management Zone II. Sample sizes were generally too low to make strong inferences of effects at well densities 100+ within 3.2km of a lek.
* A decline in number of males (relative to control leks) on remaining active leks was documented as follows: at 13-39 wells a 31% decline in Zone I and a 55% decline in Zone II; at 40-100 wells a 33% decline in Zone I and a 59% decline in Zone II.
* Findings reiterated the importance of time-lags with greater impacts 4 years after development than immediately following development.
* Found some evidence that clustering of wells within the 3.2km radius that left other areas largely undeveloped aided in lek persistence.

ATTACHMENT 4

Sage-grouse habitat selection during winter in Alberta
Carpenter et al. 2010, Journal of Wildlife Management 74(8): 1806-1814

Summary: Radio-tracked 23 females in southern Alberta during November to March 2002-2003 and 2003-2004, obtaining 296 locations. Used logistic regression in a use vs. availability approach to model habitat utilizing a variety of landscape, energy development, terrain, and vegetation variables.

Findings:
* Observed no use within 1,200m (0.75 miles) of oil/gas wells and limited use between 1,200m and 1,900m of oil/gas wells.
* Relative probability of habitat selection dropped sharply when habitat was within 1,900m (1.18 miles) of an oil/gas well.
* Concluded: "avoidance of energy development by sage-grouse in Alberta resulted in substantial loss of functional habitat surrounding wells."

Thresholds and time lags in effects of energy development on greater sage-grouse populations
Harju et al. 2010, Journal of Wildlife Management 74(3): 437-448

Summary: Evaluated the effects of energy development metrics on peak male lek attendance at 7 study areas distributed across Wyoming, analyzing data from 1996 to 2007. Used two general metrics: 1) presence of energy-related infrastructure within several spatial scales (12 spatial extents between 0.4 km and 4.8 km) surrounding a lek, expressed as a binary covariate and 2) density of well pads at the landscape level (within 8.5 km [~5 mi] of each lek). Used negative binomial regression to analyze data.

Findings:
* Observed a general pattern whereby presence of infrastructure within smaller radii (≤ 2 km) encircling leks was associated with 35-76% fewer males attending compared to leks at which no infrastructure occurred within these radii.
* Identified a general trend of decreasing male numbers with increasing well-pad density.
* Depending on the study area, a well-pad density of 4 pads/sq mile was associated with lek attendance declines ranging from 13% to 74% and a well-pad density of 8 pads/sq mile was associated with lek attendance declines of 76% to 79%.
* Data suggested that impacts may begin occurring at well-pad densities as low as 1-2 pads/sq mile and significantly fewer males were observed at leks with well-pad densities of 2-3 pads/sq mile in 4 of 6 study sites where this level of development occurred.

* Time lags that best explained the association between peak male lek attendance and well-pad density ranged from 2 to 9 years.

Greater sage-grouse winter habitat selection and energy development
Doherty et al. 2008, Journal of Wildlife Management 72(1): 187-195

Summary: Used radio telemetry to track sage-grouse in the Powder River Basin of NE Wyoming and SE Montana during the winters of 2004-2007. Used logistic regression in a used vs. available framework to evaluate habitat relationships in winter, evaluate the appropriate scale at which females select winter habitat, and assess the influence of coal-bed natural gas (CBNG) development on winter habitat selection. The final data set contained 435 use locations for building the model and 74 use locations for testing the model.

Findings:
* The top model included covariates for vegetation, topography, and gas wells: sage-grouse selected large expanses of sagebrush with gentle topography and avoided conifer habitats, riparian habitats, and CBNG development.
* After adjusting for sage-grouse habitat preference, birds avoided CBNG development in otherwise suitable habitat.
* Sage-grouse were 1.3 times more likely to use winter habitat if CBNG development was not present.

Linking occurrence and fitness to persistence: habitat-based approach for endangered greater sage-grouse
Aldridge and Boyce 2007, Ecological Applications 17(2): 508-526

Summary: Used radio telemetry on female sage-grouse to document nest and brood sites in SE Alberta, Canada from 2001 to 2004. Developed RSF models using logistic regression with a suite of predictor variables (encompassing vegetation, topography, and anthropogenic features) in a used vs. available framework. Data set included 113 nest sites and 669 brood locations, representing 35 individual broods.

Findings:
* The best nest occurrence and nest survival models did not include an energy covariate.
* Brood locations tended to be closer to well sites, but at the same time, they avoided areas with a greater density of wells within 1 km.
* The chick survival model predicts 1.5 times increase in risk for each additional oil well visible within 1 km of brood locations. As a result of choosing brood locations closer to well sites and having a lower survival probability in these habitats, a significant portion of frequently used brood habitat is classified as sink habitats.

Potential gas development impacts on sage grouse nest initiation and movement
Lyon and Anderson 2003, Wildlife Society Bulletin 31(2): 486-491

Summary: Examined distances moved from leks to nests, reproductive effort, nesting habitat, and nest success to test the null hypothesis that vehicular activity related to natural gas development had no effect on sage grouse nest site selection or productivity in the Pinedale area of NW Wyoming. Studied birds from 6 leks; 3 "disturbed" (within ≤3km of natural gas wells or haul roads) and 3 "undisturbed" (>3km from gas development OR within 3km but shielded by topography). The 3 "disturbed" leks were either directly on or immediately adjacent to a main haul road. Deployed VHF transmitters on 48 hens from 1998-1999.

Findings:
* Mean hen-movement distance from lek to nest site was significantly greater for hens captured at disturbed leks (~4.1km) than for hens captured at undisturbed leks (~2.1km).
* Nest initiation rate for hens from disturbed leks was 65% versus 89% for hens from undisturbed leks.
* Nest success did not differ between hens from disturbed versus undisturbed leks.
* Concluded that traffic disturbance of 1 to 12 vehicle trips per day in close proximity to a lek during the breeding season may reduce nest initiation rates and increase distances moved from leks during nest site selection.

<u>1202.d.(6) and (10) Columbian sharp-tailed grouse and plains sharp-tailed grouse reference summary</u>

Columbian sharp-tailed grouse reproductive ecology and chick survival in restored grasslands of northwest Colorado.
Barker 2019, Thesis, University of Wisconsin-Madison, Wisconsin, USA.

Summary: The objective of this study was to ascertain the demographic and population response of Columbian sharp-tailed grouse (CSTG) to improvements in habitat quality by increasing floristic horizontal and vertical structure and species richness in monotypic stands of non-native grasses. A before-after control-impact (BACI) design was used to look at the effects of habitat treatments on CSTG before (2015) and after the treatments (2016). The study area is northwestern Colorado within Routt and Moffat counties.

Findings:
* Over the three years of the study the number of female CSTG nesting within 2 km (1.24 miles) of the lek of capture ranged from 72.2% to 80.2% (n=275 nests monitored).
* The importance of having high quality nesting habitat in close proximity to lek sites was exemplified by the fact females nesting in agricultural fields were unsuccessful due to spring plowing of the field (n= 5/6 unsuccessful nests). After conducting habitat treatments (2016), CSTG chick body mass clearly increased among the 211 radio-marked chicks captured.

Home range and seasonal movements of Columbian sharp-tailed grouse associated with conservation reserve program and mine reclamation lands
Boisvert et al. 2005, Western North American Naturalist 65:36-44

Summary: Researchers trapped and radio-marked 156 CSTG in Northwest Colorado during 1999 and 2000. Home range sizes and seasonal movements were measured for CSTG captured within both Conservation Reserve Program (CRP) lands and on mine reclamation lands.

Findings:
* 96% of male CSTG and 77% of females remained within 2.0 km (1.24 miles) of their lek site of capture from spring through fall.
* Average distances for winter dispersal from lek sites were over 20 km for both male and female CSTG.
* Results support the 2.0 km radius used in the Habitat Suitability Index model for CSTG to assess nest and brood-rearing cover around leks, but not the 6.5 km radius used to evaluate winter cover.

Ecology of Columbian sharp-tailed grouse breeding in coal mine reclamation and native upland cover types in northwestern Colorado
Collins 2004, Thesis, University of Idaho, Moscow, USA.

Summary: This study compared ecological parameters of Columbian sharp-tailed grouse associated with mine reclamation and shrub-steppe cover types and provide recommendations to wildlife managers that will assist in formulating appropriate management strategies for CSTG. This study occurred in Moffat, Routt, and Rio Blanco counties, Colorado from 2001 -2003.

Findings:
* 80-85% of females nested within 2 km (1.2 miles) of their lek of capture depending on study site, shrub-steppe and mine reclamation, respectively.
* In the mine reclamation study site 100% of females raised their broods within 2.0 km * (1.2 miles) of where they nested and in the shrub-steppe study site 79% of

females raised their broods within 2.0 km of where they nested.* CSTG remained on their breeding range until late October – early November.
* In shrub-steppe areas 80% (4 of 5) males remained <1 km (0.6 mile) from their lek of capture the entire winter.

Landscape changes within the historical distribution of Columbian sharp-tailed grouse in eastern Washington: is there hope?
McDonald and Reese 1998, Northwest Science 72:34-41

Summary: Landscape changes within the historical distribution of CSTG in eastern Washington were assessed and analyzed to predict the most suitable areas for habitat improvements.

Findings:
* Suitable habitat for CSTG has decreased drastically across eastern Washington. Primarily from the conversion of native grasslands and sagebrush to agricultural pasture and farmland.
* These habitat declines have corresponded with significant population declines of CSTG in Washington.
* Habitat enhancement efforts for CSTG should be conducted near existing core populations to increase the chances of viable range expansions. Additionally, efforts should be made to connect CSTG populations to allow for movements and genetic dispersal.

Habitat use and movements of sympatric sage and Columbian sharp-tailed grouse in southeastern Idaho
Apa 1998, Dissertation, University of Idaho, Moscow, USA

Summary: This study examined the habitat use and movements of sympatric female sage and Columbian sharp-tailed grouse (CSTG) during the breeding, nesting, and brood-rearing periods within southeastern Idaho between 1988 and 1991.

Findings:
* CSTG nest success was higher within areas of native vegetation (100%) versus areas of non-native vegetation (45%).
* CSTG nested much closer to the lek of capture than greater sage-grouse in the same area. Additionally, nesting areas varied by elevation with sage-grouse nesting at higher elevation sites compared to CSTG.

ATTACHMENT 4

Grassland bird assemblage conservation element analysis for the northwestern plains ecoregion
Bureau of Land Management, 2012, Rapid Ecoregional Assessment (REA), Appendix E-4.

Summary: It is recognized that oil and gas development in North Dakota is occurring at a rapid pace and agencies do not have a full understanding of the potential risk of these activities to grassland bird species [including plains sharp-tailed grouse (PSTG)].

Findings:
* The potential for oil and gas development throughout the Northwestern Plains has the potential to affect the grassland bird assemblage modeled habitat.
* As more roads, oil and gas development, wind farms, and other features are constructed across the ecoregion [Northwestern Plains Ecoregion - northeastern Wyoming, southeastern Montana, western South Dakota, southwestern North Dakota], the fragmentation of the native prairie is expected to increase, further decreasing the amount of suitable habitat in large enough patches to be used by breeding pairs (USFWS 2011).
* Oil and gas potential production poses a moderate risk to grassland bird habitats including PSTG. This assessment was based on oil and gas density data and larger potential production extents were used to qualitatively assess the potential effect of future oil and gas production activities. Therefore, a carefully considered approach should be taken when assessing the effect of potential oil and gas production areas on grassland bird assemblage modeled habitat.

Impacts of oil and gas development on sharp-tailed grouse on the Little Missouri National Grasslands, North Dakota
Williamson 2009, Theses and Dissertations, South Dakota State University, 604.

Summary: Oil and gas development and their attendant structures (i.e., power lines, roads and collection stations) have increased across western North America since the 1930s, resulting in direct habitat loss, and fragmentation of remaining suitable habitat. Although numerous studies have shown oil and gas development has impacted many avian species, particularly sage grouse (*Centrocercus urophasianus*), little is known about the effects of oil and gas development on sharp-tailed grouse (*Tympanuchus phasianellus*). This 2-year study was initiated to determine the impacts of oil and gas development on PSTG (*T. p. jamesi*) on the Little Missouri National Grasslands in North Dakota.

Findings:
* Both short- and long-term habitat losses may be associated with energy development.
* Available habitat across the entire study site appeared to be the driving force for where PSTG nested and spent the brood-rearing period.
* Brood survival varied between the two sites (one area with oil and gas presence and the other that is free from development). Other reproductive factors did not vary between the sites.
* Authors recommended that supporting agencies focus their management actions on the remaining PSTG leks within the oil field, particularly in areas where the current oil and gas development is expanding into.
* Authors noted that leks are the focal point for annual reproduction and movements of the remaining grouse and if these habitats are severely altered or lost, the PSTG population within the oil field may experience a decrease in numbers.

Relating grouse nest success and corvid density to habitat: a multi-scale approach.
Manzer and Hannon 2005, Journal of Wildlife Management 69(1): 110-123

Summary: This study looked at how human-caused habitat change affected predator and prey by using habitat variables to model nest selection, corvid density, and nest success for sharp-tailed grouse (*Tympanuchus phasianellus*) in Alberta, Canada.

Findings:
* [PSTG] Nests were >4 times more likely to succeed in areas with <10% crop and <35% crop and sparse grassland (aggregated) at the 1,600-m extent; hence, landscapes that are close to these thresholds could be prioritized for broad-scale action.

Locating sharp-tailed grouse leks from color infrared aerial photography
Grensten 1987, U.S. Bureau of Land Management Technical Note 377. U.S. Department of the Interior, Bureau of Land Management, Billings, Montana, USA.

Summary: Locating sharp-tailed grouse (*Pedidecetes phasianellus*) leks is important in identifying and evaluating their habitat.

Findings:
* Sharp-tailed grouse mate, nest, rest, feed, raise brooks, and winter within 1.5 miles (3.2 km) of leks. Thus, if lek locations are known, crucial yearlong habitat can be identified.

* Crucial habitats are defined as portions of the habitats of sensitive species that if destroyed or adversely modified could result in their being listed as threatened or endangered pursuant to Section 4 of the Endangered Species Act or in some category implying endangerment by a State agency or legislature.

A grassland conservation plan for prairie grouse
Vodehnal and Haufler 2007, North American Grouse Partnership, Fruita, CO.

Summary: Prairie grouse, including all species of prairie-chicken and the sharp-tailed grouse, have declined precipitously and steadily from historical levels throughout the Great Plains of North America. While many factors have contributed to these declines, the loss and fragmentation of expansive prairies to farming, and the reduction of habitat quality within remaining prairie fragments are known to be the primary causes.

Findings:
* Energy exploration and development occur on public and private surface lands throughout the range of prairie grouse within BCR 18 [Bird Conservation Region 18 - or eastern Colorado among 7 other states].
* Although the effects of oil and gas developments on prairie grouse are poorly understood, recent studies have suggested that development of oil and gas resources negatively impacts prairie grouse, particularly during the breeding season.
* Prairie grouse require large contiguous tracts of prairie ecosystems to fulfill their life history requirements. The cumulative impacts of roads and increased traffic, well pads, pipelines, overhead transmission lines, compressor stations, and production facilities not only result in direct habitat loss but fragment remaining suitable habitat deterring use by prairie grouse (Pitman et al. 2005).

<u>1202.d.(7) Greater prairie chicken production areas reference summary</u>

Nest site selection and nest survival of greater prairie-chickens near a wind energy facility
Harrison et al. 2017, The Condor Ornithological Applications 119:659–672.

Summary: This study investigated nest site selection and nest survival for greater prairie chickens near an existing wind energy facility the Nebraska Sandhills.

Findings:
* The primary drivers of nest site selection and nest survival were related to landscape and habitat factors.

* Greater prairie-chickens avoided nesting near roads, with 74% selecting nest sites >700 m from roads.
* There was little evidence from this study that wind turbines had an influence on nest site selection
* Greater prairie-chickens selected nest sites with more than twice the visual obstruction and residual standing dead vegetation of random point.

Management of Sandhills rangelands for greater prairie-chickens
Powell et al. 2015, University of Nebraska-Lincoln. Lincoln, NE.

Summary: This study outlines the best means of managing this region to promote the success of this native year-round resident of the Nebraska Sandhills.

Findings:
* The majority of hens nest within 2 miles of a lek in Nebraska.
* Prairie chickens find sites for nesting that have tall, dense vegetation with relatively high VOR [Visual Obstruction Reading] as compared to surrounding areas (about 4.5 inches in upland pastures). These high VOR patches are generally less than 10 feet in diameter and are surrounded by shorter grasses with a VOR of about 2.5 inches. Researchers believe that these females choose such sites because they want to find protection for their nest in these denser clumps while still being able to see any coming predators in Nebraska.
* Recommendations included keeping 30-50% of lands within one mile of leks as hospitable nesting grounds to help maintain and increase prairie-chicken populations.

Female greater prairie-chicken response to energy development and rangeland management.
Londe et al. 2019, Ecosphere 10(1):e02982

Summary: The study evaluated greater prairie-chicken use locations to understand the importance of spatial scale and temporal patterns as well as response to anthropogenic activities and energy infrastructure in Oklahoma between 2014 and 2016. The authors used discrete choice models to evaluate greater prairie-chicken resource use during the lekking, nesting, post-nesting, and non-breeding seasons.

Findings:
* Time since fire, proximity to woodlands and proximity to lek sites were the most consistent predictors of habitat use during most periods and spatial scales.
* Greater prairie-chickens demonstrated a seasonally variable response to energy development, avoiding powerlines and areas with high densities of oils wells by as much as 300 - 600 m in the lekking, post-nesting, and non-breeding season.

* Female prairie-chickens appeared to be the most sensitive to oil and gas development during the post-nesting and nonbreeding seasons.
* Avoidance distances differed across the season, but avoidance distances generally estimated avoidance thresholds up to 300–600 for power lines, 300 m to as much as 1000 m for oil wells, and approximately 80– 100 m from roads.
* While distance to oil wells was supported as being a potentially important predictor of prairie-chicken habitat use during the postnesting and nonbreeding seasons, density-related variables consistently provided better estimates of prairie chicken habitat use suggesting prairie-chicken may be more sensitive to the number and spatial arrangement of wells rather than distance to wells.
* The magnitude of effect was stronger in the nonbreeding season where the addition of a single oil well per km^2 reduced probability of use by 27% compared to a 14% lower probability of use for the post-nesting season.
* Efforts should be made to limit future fragmentation of grassland by energy development.

Space use of female greater prairie-chickens in response to fire and grazing interactions.
Winder et al 2017, Society for Range Management 70(2): 165-174

Summary: The study occurred in Flint Hills of Kansas and investigated the spatial ecology of female greater prairie-chicken in rangeland managed through grazing and patch-burn grazing.

Findings:
* Distance to lek was consistently the strongest predictor of space used during both the breeding and nonbreeding seasons.
* Centroids of breeding home ranges tended to be about 1 km from a lek, 1.7 from the nearest road, 0.5 km from a patch edge.
* Distance from home range centroid to the nearest lek was ~1 km during the breeding season and ~2.5 km during the nonbreeding season.
* Greater than 97% of females had breeding home range centroids <5 km from the nearest lek.

Status and management of the greater prairie-chicken (*Tympanuchus cupido pinnatus*) in North America.
Svedarsky et al. 2000, Wildlife Biology 6(4):277-284

Summary: This is a summary of the distribution of greater prairie-chicken by state across the range.

Findings:
* Greater prairie-chickens are a grouse of the tallgrass prairie of North America.
* The range of greater prairie-chicken increased during early European settlement, then decreased when the optimum mix of cropland and grass was exceeded. Historically greater prairie-chickens probably occurred in 20 states and four Canadian provinces, but presently only occur in 11 states and are no longer present in Canada.

Greater Prairie-Chicken (*Tympanuchus cupido*): A Technical Conservation Assessment
Robb, L.A, and M.A. Schroeder. 2005. Prepared for the USDA Forest Service, Rocky Mountain Region - Species Conservation Project. Peer Review Administered by the Society for Conservation Biology.

Summary: A species conservation assessment for greater prairie chicken populations in the Rocky Mountain Region summarizing the scientific knowledge and implication of that knowledge for species management.

Findings:
* The major threats to greater prairie-chicken populations in Region 2 are the loss, fragmentation, and degradation of potential and occupied habitat on both private and public lands, which could occur through inappropriate timing and intensity of livestock grazing, conversion of native prairie for development and crop production, construction of roads, utility corridors, fences, towers, turbines, and energy developments, alteration of fire regimes, and planting of trees.
* Populations in the region are particularly vulnerable to changing land use practices that degrade or eliminate nesting and brood-rearing habitats. In addition, small, localized populations that are isolated from core areas may face greater risk of extinction due to a lack of connectivity.
* Drought can increase the intensity of these impacts.
* Features associated with human development also contribute to habitat fragmentation and introduce disturbance and mortality factors.

Predicting greater prairie-chicken lek site suitability to inform conservation actions
Hovick et al. 2015, PLoS ONE 10(8):e0137021

Summary: This study included nine years of data on 870 greater prairie-chicken lek sites in Kansas and utilized land cover and anthropogenic data layers to model lek site suitability.

Findings:
* Elevation was the most influential variable when predicting lek locations.
* Models were improved with the addition of land cover and anthropogenic features including power lines, roads, and oil and gas structures.
* When land features and vegetation cover are suitable for Greater Prairie-Chickens, fragmentation by anthropogenic sources especially roadways and transmission lines are a concern.

1202.d.(9) Lesser prairie chicken reference summary

The Lesser Prairie-Chicken Range-wide Conservation Plan.
Van Pelt et al. 2013. Western Association of Fish and Wildlife Agencies. Cheyenne, Wyoming.

Summary: The Lesser Prairie Chicken Range-wide Plan (RWP) was developed by the five lesser prairie-chicken states (Colorado, Kansas, New Mexico, Oklahoma, and Texas), along with oil and gas and electric utility companies, private landowners, and the U.S. Fish and Wildlife Service, as a comprehensive adaptive plan designed to conserve lesser prairie-chickens across the range. Avoidance, minimization, and mitigation actions are primary actions identified and implemented under the RWP. The Conservation Strategy outlined in the RWP has two main objectives: concentrates limited resources for species conservation in the most important areas, allowing for the restoration, enhancement, and maintenance of large blocks of habitat needed by LPC and secondly, identifies areas where development should be avoided, which also helps identify areas where development is of less concern for LPC. This provides developers with the guidance they typically seek for their development planning purposes and helps avoid conflicts over impacts to the species.

Findings:
* RWP avoidance measures include lek surveys in project areas to identify leks and avoidance of habitat loss or fragmentation within focal areas, connectivity zones, and within 1.25 miles of known leks that have been active at least once within the previous five years.
* Minimization actions include seasonal use restrictions, noise abatement, co-location of facilities, and other best management practices.
* Where avoidance is not possible, the RWP develops a mitigation framework and program.

ATTACHMENT 4

Spatially explicit modeling of lesser prairie-chicken lek density in Texas
Timmer et al. 2014, The Journal of Wildlife Management 78(1):142-152

Summary: estimated lek density in the occupied lesser prairie-chicken range of Texas, USA, and modeled anthropogenic and vegetative landscape features associated with lek density to examine how lek density may respond to changes on the landscape related to an increase in energy development. Anthropogenic features included paved road density, unpaved road density, all road density, density of transmission lines, and active oil/gas pad density.

Findings:
* Lek density increased with an increase in total proportion of grassland and shrubland.
* Lek density was inversely related to active oil and gas well density.
* Paved and unpaved road density was inversely related to lek density.
* Lek density was greatest in areas with higher proportion of shrubs and grasslands and lower. densities of paved roads and lower densities of active oil and gas wells.

Strategic conservation for lesser prairie-chickens among landscapes of varying anthropogenic influence
Sullins et al. 2019, Biological Conservation 238: 108213

Summary: The authors estimated the distribution of lesser prairie-chicken using data from 170 birds marked with GPS transmitters in Kansas and eastern Colorado between 2013 and 2016. Data was collected at 6 study sites (3 in Kansas and 3 in Colorado) that varied in density of anthropogenic features and species distribution was modeled from the GPS location data and evaluated relative to vegetation and densities of paved and county roads, transmission lines, oil wells, and other vertical features.

Findings:
* Overall the relative probability of use by lesser prairie-chickens decreased as cumulative densities on anthropogenic features increased.
* Based on the raw probability distribution, the occupancy threshold for vertical point feature densities occurred at ~ 2 vertical features per 12.6 square kilometers (2-km radius). A similar threshold was estimated for oil wells, with areas having more than two oil wells per 12.6 square-kilometers having 8 times lower relative probability of use.
* The model suggested decreased probability of use in 2-km radius landscapes that had greater than two vertical features, two oil wells, 8 km of county roads, and 0.15 km of major roads or transmission lines.
* Predicted probability of use was greatest in 5-km radius landscapes that were 77% grassland.

* Based on predictions, around 10% of the current expected lesser prairie-chicken distribution was available as habitat.
* Broad scale (78.5 km 2) grassland composition and anthropogenic feature densities appear to exert constraints on the distribution of lesser prairie-chickens in the study area.

Balancing energy development and conservation: a method utilizing species distribution models
Jarnevich and Laubhan 2011, Environmental Management 47:926-936

Summary: The study used lek locations from 7 years of survey data in Kansas to examine the distribution of leks relative to environmental factors related to prairie habitat and anthropomorphic factors including highways, oil and gas wells, and electric transmission lines.

Findings:
* Amount of tall grass prairie and grassland were the most influential vegetation factors in lek placement along with lower standard deviation in elevation.
* Anthropomorphic factors had a lower contribution to lek placement compared to habitat variables however leks closer to these features had lower habitat suitability. Distance from oil or gas wells was the most influential anthropogenic feature affecting lek occurrence (for lek locations recorded after 1995) in Kansas and oil or gas well density was the most influential anthropomorphic feature affecting lek occurrence at the largest scale.

Investigation into the decline of populations of the lesser prairie-chicken (*Tympanuchus pallidicinctus*) in southeastern New Mexico.
Hunt 2004, Dissertation, Auburn University, Auburn, Alabama, USA.

Summary: The study examined the relationship between oil and gas development and decline in populations of lesser prairie-chickens in southeastern New Mexico by evaluating 41 active leks and 32 abandoned leks relative to the presence of oil wells, roads, and power lines. Abandoned leks had more active wells, more total wells, and greater length of road than active leks, and were more likely than active leks to be near power lines.

Findings:
* Average number of active wells within 1 mile of active leks was 1, while the average number of active wells within 1 mile of abandoned leks during their last active year was 8.
* Abandoned leks had an average of 26.7 km (16.0 miles) of road and density of roads of 3.3 km/km^2 (5.1 miles/miles^2). Active leks had an average of 20.0 km (12.0 miles)

of road and density of roads of 2.4 km/km^2 (3.7 $miles/miles^2$). Abandoned leks had a greater proportion of area within 1.6 km (1 mile) that was within 31 m (100 feet) and 152 m (500 feet) of roads than did active leks.

* Eighteen of 40 abandoned leks (45%) were within 800 m (2,600 feet) of at least one power line, while only 1 of 33 active leks (3%) was near a power line.

Biological Resource & Description	300 Series	400 Series	600 Series	900 Series	1000 Series	1200 Series
Vegetation	**303.a.(5).B.iv:** Ecosystems data on Form 2B for CIDER	**406.e.(4).F:** Plugging conductors & reclaiming vegetation	**603.d:** Consolidates development onto multi-well pads, reducing vegetation disturbance	**907.h.(1).A**: Requires planning for reclamation of centralized E&P waste facilities	**1001.a**: Restores surface to condition prior to O&G operations	Habitat benefits discussed below also protect vegetation.
Numerous vegetative communities in Colorado may be impacted by oil and gas including cropland, rangeland, and wetlands.	**304.b.(2).B.vii**: ALA in HPH and wetlands & riparian corridors	**407.a**: Construction report allows timely interim reclamation inspection			**1002.d & e.(1)–(4)**: Minimizing surface disturbance preserves vegetation	
	304.b.(4).A–C: Location photos to identify reference area vegetation	**412.a.(4)–(6)**: Protects agricultural activities through surface owner notification	**606.c:** requires oil and gas locations to be kept free of undesirable plant species, including noxious weeds	**913.b.(5).B.iii**: Minimizes impacts of reclamation remediation activities on vegetation	**1002.f:** Stormwater protections maintain vegetation by reducing erosion	**1202.a.(8):** Timing limitations for vegetation removal encourage plant growth reproduction and avoids disturbance during pollination season.
The Commission's Reclamation Rules are intended to restore vegetated areas to their condition pre-development	**304.b.(9).B:** Identifying reference area for future reclamation	**427.a & 427.e.(3)**: protects vegetation from burial through dust plan & standards			**1003**: Interim reclamation restores a major portion of total disturbed vegetation	
	304.c.(15): Stormwater management plan	**436.e.(4).A**: requires protecting vegetation in seismic operations		**913.b.(6)**: Assures proper reclamation remediation sites	**1003.e.(1)**: Restoration and revegetation on croplands	
	304.c.(16): Interim reclamation plan	**436.h**: requires reclamation after seismic operations, including revegetation			**1003.e.(2)**: Restoration & revegetation on non-crop lands; restoration to reference area & limit noxious weeds	
The vegetative conditions prior to development are identified through the reference area analysis on the Form 2A	**313.b.(6)**: planning reclamation for seismic operations					
	314.e.(6): CAPs will consolidate infrastructure, reducing impacts on vegetation				**1004.a**: Reclamation w/in 3 months on cropland & 12 months on non-crop land to fully restore vegetation	
	314.e.(10).D & E: Ecosystems data for CAP cumulative impacts analysis				**1004.c & d**: Vegetation requirements for final reclamation	

Biological Resource & Description	300 Series	400 Series	600 Series	900 Series	1000 Series	1200 Series
Wildlife & Wildlife Habitat	**303.a.(5).B.iv**: Wildlife & habitat disturbance data on Form 2B for CIDER	**406.e.(1) & (3)–(4)**: Prevents wildlife from being trapped in conductors and cellars	**603.d:** Consolidates development onto multi-well pads, reducing habitat disturbance	**909.f**: Fencing and netting new pits to prevent wildlife from entering pits	**1002.f**: Stormwater protections benefit aquatic species	**1201**: Wildlife protection and mitigation plans for new locations
The Commission's Rules protect wildlife and their habitat through numerous Rules, including in the 1200 Series	**304.b.(2).B.viii**: ALA in High Priority Habitat ("HPH")	**405.b, d, & q**: Form 42 notice of key activities sent to CPW				**1202.a**: Statewide operating standards to protect wildlife
	304.b.(14): Wetlands information on Form 2A	**Tbl. 423-1 & 423.b.(4)**: Sets standards to protect wildlife from noise in HPH, State Parks, and State Wildlife Areas	**606.d.(3).B:** Requires trash containers to exclude wildlife	**912.b.(10)**: CPW notice of spills & releases in HPH & riparian areas		**1202.b:** HPH operating standards to protect wildlife
	304.c.(17): Wildlife protection plan		**612**: Protects wildlife species that are highly sensitive to H2S			**1202.c**: Defines most protected HPH
Wildlife in Colorado include not only larger mammals like deer and elk, but also fish and invertebrate species, including pollinators.	**309.e:** Consultation with CPW about wildlife protection	**424**: Protect nocturnal species from lighting		**913.b.(5).B.i**: Fencing & covering open excavations during remediation		**1202.d:** Defines HPH for compensatory mitigation
	312.d: COAs to protect wildlife during subsequent operations	**436.e.(4).C**: Filling seismic operations holes prevents wildlife from becoming trapped				**1203.a**: Requires compensatory mitigation in HPH
	314.e.(6): CAPs will consolidate infrastructure, reducing habitat fragmentation					**1203.c**: Sets fee for compensatory mitigation of direct impacts
	314.e.(10).D: Wildlife data for CAP cumulative impacts analysis					**1203.d**: Compensatory mitigation for indirect impacts
	314.f.(4).B: CPW consultation on CAP wildlife impacts					**1203.b**: Compensatory mitigation plans

Biological Resource & Description	300 Series	400 Series	600 Series	900 Series	1000 Series	1200 Series
Topsoil	**303.a.(5).B.v**: Topsoil disturbance data on Form 2B for CIDER database	**405.b**: Notice of construction allows inspectors to be onsite when topsoil is salvaged		**913.b.(5).B.ii**: Protection of topsoil during remediation activities	**1001.a**: Requires reclamation to ensure protection of topsoil	
Healthy topsoil is a critical biological resource because it allows for ecosystem dynamics to function, such as nutrient cycling	**304.c.(14)**: Topsoil protection plan	**406.b**: Further facilitates inspection of topsoil salvage activities		**913.b.(5).B.iii**: Surface disturbance miniminization during remediation activities	**1002.b.(1)–(3)**: Requires soil removal, segretation, and storage on both cropland and non-crop land	
	309.b.(1).C: Identify best management practices for topsoil during surface owner consultation				**1002.c**: Protects stockpiled soils	
	312.d: COAs to protect the environment during subsequent operations				**1002.d**: Minimizing total surface disturbance from working pad surface locations to protect intact topsoil	
	314.e.(10).E.i: Topsoil disturbance data for CAP cumulative impacts analysis				**1003.e**: Soil replacement to original position	
					1003 & 1004: General standards for interim and final reclamation protect topsoil from loss due to wind and water erosion	

Biological Resource & Description	300 Series	400 Series	600 Series	900 Series	1000 Series	1200 Series
Ecosystems, Habitat Heterogeneity, and Biodiversity	**303.a.(5).B.iv:** Ecosystem disturbance data on Form 2B for CIDER database	**423**: Mitigates noise that impacts different species differently and influences bird diversity near oil and gas locations	**603.d:** Consolidates development onto multi-well pads, reducing ecosystem impacts	**913.b.(5).B.iii**: Reduced surface disturbance during remediation protects habitat	**1003**: Interim reclamation rules require that revegetation be established to reflect reference area forbs, shrubs, and grasses which ensures diversity	**1202.a.(6)**: Ensures a diverse seed mixture appropriate for ecosystem restoration is used
Some of the Commission's Rules consider impacts at a broader scale and are intended to address broader protection of ecosystems and biodiversity, rather than benefitting only one location or species individuals	**303.a.(5).B.v.BB:** Qualitative analysis of incremental adverse impacts to ecosystems on Form 2B for CIDER database		**606.c:** requires oil and gas locations to be kept free of undesirable plant species, including noxious weeds		**1004**: Final reclamation rules require that revegetation be established to reflect reference area forbs, shrubs, and grasses, which ensures diversity	**1203.b.(1).E**: Compensatory mitigation plans, must include baseline information on wildlife resources, not otherwise restricted by species or habitat type.
	314.e.(10).D: Ecosystem disturbance data for CAP cumulative impacts analysis					
	314.e.(10).E.ii: Qualitative analysis of incremental adverse impacts to ecosystems for CAP cumulative impacts analysis					

Biological Resource & Description	300 Series	400 Series	600 Series	900 Series	1000 Series	1200 Series
Invasive Species Management		**436.g.(2) & h**: Require reclamation after seismic operations, which includes weed control	**606.c:** Keeping location free of undesirable plant species includes noxious weed control		**1003.f**: Weed control during drilling, production, and recalmation operations to keep sites free of noxious weeds and undesirable plant species	**1202.a.(2)**: Disinfection and other precautions to kill aquatic nuisance species and avoid spreading aquatic invasives
Colorado's native ecosystems are a biological resource, and the Commission's Rules intended to manage invasive species benefit native species.					**1004.e**: Weed control at final reclamation to keep sites free of noxious weeds and undesirable plant species	**1202.a.(9)**: Treat water stored in pits to prevent spread of west nile virus.

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 22058
(CONTINUED)
ORDER NO. 24665

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER AMENDING THE CURRENT BAKKEN, BAKKEN/THREE FORKS, AND/OR THREE FORKS POOL FIELD RULES TO RESTRICT OIL PRODUCTION AND/OR IMPOSE SUCH PROVISIONS AS DEEMED APPROPRIATE TO REDUCE THE AMOUNT OF FLARED GAS.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause originally came on for hearing at 9:00 a.m. on the 22nd day of April, 2014.

(2) North Dakota Industrial Commission (Commission) Order No. 24392, signed May 14, 2014 continued the decision in this matter for an additional ninety days.

(3) This hearing was called on a motion of the Commission to consider amending the current Bakken, Bakken/Three Forks, and/or Three Forks Pool field rules to restrict oil production and/or impose such provisions as deemed appropriate to reduce the amount of flared gas.

This special hearing was scheduled to address the Commission's newly-adopted policy on reducing gas flaring. The policy goals were to reduce the flared volume of gas, reduce the number of wells flaring, and reduce the duration of flaring from wells.

Action items to reach the policy goals included requiring Gas Capture Plans for increased density, temporary spacing, and proper spacing cases; requiring Gas Capture Plans for all applications for a permit to drill; schedule semi-annual meetings with midstream gas gathering companies to gauge the effect of Gas Capture Plans, production curtailments, contracts, and service interruptions; dedicate information technology resources to develop a web-based pipeline incident report form to better assess right-of-way issues; direct the Pipeline Authority to track flaring on/off the Fort Berthold Indian Reservation and report capture status versus goals; and docket this hearing to review and revise Bakken, Bakken/Three Forks, and/or Three Forks Pool rules governing production curtailment.

(4) Prior to the hearing, the Commission indicated it was seeking testimony of technical nature for input on the following:

a. Length of time wells should be allowed to produce at maximum while flaring?
b. What production rate restrictions are appropriate for wells connected to gas gathering or beneficial uses?
c. What types of administrative approval of exemptions from production restrictions are appropriate?
d. What consideration should be given to ambient air quality regarding production rates or restrictions?
e. Should production rates and restrictions be adjusted for well economics and percentage of gas captured by well site, field-pool, region or operator?
f. Should production rates for wells not connected to gas gathering or beneficial uses be reduced in stages or set at a low rate after payout?

Written comments were allowed no later than 5:00 p.m., Monday, April 21, 2014.

(5) The Commission received written comments from Toby Schweitzer of Bakken Frontier LLC, Caleb Young employed in the oil and gas industry, Srini Raghavan of Navi Reliance Group LLC, Gary Preszler of the North Dakota Chapter of the National Association of Royalty Owners, Alexis Brinkman of the North Dakota Petroleum Council, Roger Kelley of Continental Resources Inc. representing the Domestic Energy Producers Alliance, Tex Hall of the Mandan Hidatsa and Arikara Nation, Gordon Vaskey of Zavanna LLC, Taylor Reid of Oasis Petroleum North America LLC, Kenneth Klanika of Statoil Oil and Gas LP, Danette Welsh of ONEOK Inc., Dominic Spencer of Triangle USA Petroleum Corporation, Andrew Logan of Ceres, Mark Borla of SM Energy Company, Lisa Casarez a member of the Fort Berthold Indian Reservation, Adam Bishop of Hunt Oil Company, Abby Sharp and Kimberly Croll of Caliber Midstream Partners LP, Mark Wald of Blaise Energy, Jeremy Conger of WPX Energy Williston LLC, James Kennedy of Fidelity Exploration & Production Company, Ralph Castille of ConocoPhillips Company, Jeff Herman of Petro-Hunt LLC, Joel Noyes of Hess Corporation, Don Morrison of the Dakota Resource Council, Brent Miller of Whiting Oil and Gas Corporation, Stephanie Chase of the Environmental Law & Policy Center, and Wessel Nel of Hatch Ltd.

The following concerned land/royalty owners also submitted written comments: Tim Stroh and Eugene Bardal.

The following concerned citizens also submitted written comments: Wally Stephens, Peggy Klein, Al Coen, Susan and Paul Bultsma, Carol Nelson, Lyle and Susan Best, Pete and Vawnita Best, Galen Grote, Norma Stenslie, Joletta Bird Bear, James Stewart, Corinne L., Shelly Ventsch, Candance Kraft, Rose Veeder, Cedar Gillette, and Curtis Bardal.

(6) The Commission received oral comments at the hearing from Lyle Best a landowner near Watford City, Ron Ness of the North Dakota Petroleum Council, Brad Aman of Continental Resources Inc., Roger Kelley of Continental Resources Inc. representing the Domestic Energy Producers Alliance, Jeremy Conger of WPX Energy Williston LLC, Brent Miller of Whiting Oil and Gas Corporation, Danette Welsch of ONEOK Inc., Brian Cebull of GUIT LLC, Ralph Castille of ConocoPhillips Company, Theodora Bird Bear of the Dakota Resource Council, Scott Skokos of the Dakota Resource Council, Lance Langford of Statoil Oil & Gas LP, Tony Lucero of

Enerplus Resources USA Corporation, Tom Wheeler of Northwest Landowners Association, Mark Borla of SM Energy Company, Bryant Winn of Petro-Hunt LLC, Dan Grossman of the Environmental Defense Fund, Jerrold Mayer of Zavanna LLC, Walter Breidenstein of Gas Technologies, Wayde Schafer of the Sierra Club, Andy Peterson of the Greater North Dakota Chamber, Toby Schweitzer of Bakken Frontier LLC, Carey Doyle of the Mandan Hidatsa and Arikara Nation, and William McCabe of Missouri River Resources.

(7) Having allowed all interested persons an opportunity to be heard and having heard, reviewed, and considered all testimony and evidence presented, the Commission makes the following conclusions. Much of the testimony was relevant, but did not address the six topics on which the Commission sought testimony.

(8) The typical Bakken, Bakken/Three Forks, and/or Three Forks Pool is defined as that accumulation of oil and gas found in the interval from 50 feet above the Bakken Formation to above the top of the Birdbear Formation within the limits of any given field. To ease confusion, the Pool will collectively be hereinafter referred to as the Bakken Pool.

(9) Development of Bakken Pools in North Dakota is currently ongoing and encompasses over 15,000 square miles of land. Total gas plant capacity in North Dakota exceeds total gas production in the state although many bottlenecks exist in the current gas gathering infrastructure due to the high liquid content of the gas, the prolific volumes of oil and gas during initial production, increasing pipeline pressure that requires installation of additional compressors, and in some cases undersized pipe. Most operators are prudently attempting to connect their wells to a gas gathering system, but due to many aforementioned constraints in the gas gathering systems, much of the gas is not processed.

(10) Bakken Pools producing in North Dakota are oil reservoirs and gas is produced in association with the oil at the wellhead as a by-product of oil production. The value of the oil produced far exceeds the value of any gas produced in association with the oil.

(11) Leasehold interests in some Bakken Pool spacing units are not yet held by production. The initial horizontal well drilled in such spacing units should be allowed to produce at its maximum efficient rate, regardless if the well is connected to a gas gathering system. Allowing such wells to produce at a maximum efficient rate will allow valuable information to be obtained in order to make decisions with regard to future wells and infrastructure requirements in the spacing unit.

(12) Some Bakken Pool spacing units are being developed where the operator is aware that the existing gas gathering infrastructure is insufficient to allow surplus gas to be processed through the gas gathering system. In instances where significant amounts of surplus gas is flared due to the insufficient collection system, production should be restricted unless significant amounts of surplus gas is captured for beneficial consumption, or utilized in a value-added process.

(13) Some Bakken Pools could have up to five separate horizontal targets, resulting in as many as twenty-eight wells within the same spacing unit.

(14) Various time frames for maximum efficient rates were suggested. North Dakota's production of Bakken Pool associated gas is typically associated with an unusually high

temperature, pressure, and liquid content. Initial production decline is also very rapid, due to the highly fractured nature of the completion interval.

(15) The Commission believes the North Dakota Petroleum Council's Flaring Task Force's targets of capturing 74% of the gas by October 1, 2014; 77% by January 1, 2015; 85% by January 1, 2016; and 90% by October 1, 2020 with potential for 95% capture are attainable and should be adopted as gas capture goals by the Commission. The restrictions imposed by this order will strive to meet such goals.

(16) Production restrictions imposed by the Commission will constitute force majeure in most producer/gas gatherer contracts and excuse parties from performing certain parts of the contract while production restrictions are imposed.

(17) Delineation drilling activity versus multi-well development requires separate and unique solutions.

(18) Pipeline construction across rough topography or around surface waters causes delays in connecting wells to a gas gathering system.

(19) Flexibility is required due to surface landowner, tribal, and federal government right-of-way delays; temporary midstream down-time for system upgrades and maintenance; federal regulatory restrictions or delays; safety issues; delayed access to electrical power; and possible reservoir damage.

(20) Well payout and economics should not be used to determine production restrictions.

(21) Some well site value-added processes that utilize the surplus gas in a beneficial manner are economic.

(22) Commission production records indicate the majority of gas flared in North Dakota is from wells already connected to a gas gathering system. Such wells should not be excluded from gas capture goals adopted by the Commission.

(23) Some flared gas contains components that if improperly combusted could cause air quality degradation and health issues.

(24) On the Fort Berthold Indian Reservation, many Bakken Pools are also within the jurisdiction of the Mandan Hidatsa and Arikara (MHA) Nation and Bureau of Land Management (BLM). In some cases, companies must comply with MHA Nation, BLM, and Commission rules. The Commission should work with federal and tribal authorities to ensure that restrictions imposed herein provide clarity and protection of correlative rights for the oil and gas companies operating in the respective jurisdictions.

(25) The production allowances and restrictions imposed herein will provide for the effective and efficient recovery of oil from the Bakken Pool, encourage rapid development, avoid the drilling of unnecessary wells, and prevent waste in a manner that will protect correlative rights.

IT IS THEREFORE ORDERED:

(1) All Commission orders allowing wells completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool to produce at a maximum efficient rate shall remain in full force and effect through September 30, 2014. All wells completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool are hereafter allowed to produce at a maximum efficient rate through September 30, 2014. After September 30, 2014, the gas capture from all existing wells shall be evaluated and oil production from all existing and future wells shall not exceed the production allowances herein.

(2) The first horizontal well completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool non-overlapping spacing unit shall be allowed to produce at a maximum efficient rate.

(3) All wells completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool that have received an exemption to North Dakota Century Code Section 38-08-06.4 shall be allowed to produce at a maximum efficient rate.

(4) All infill horizontal wells, including overlapping spacing units, completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool, shall be allowed to produce at a maximum efficient rate for a period of 90 days commencing on the first day oil is produced through well-head equipment into tanks from the ultimate producing interval after casing has been run; after that, such wells shall be allowed to continue to produce at a maximum efficient rate if the well or operator meets or exceeds the Commission approved gas capture goals. The gas capture percentage shall be calculated by summing monthly gas sold plus monthly gas used on lease plus monthly gas processed in a Commission approved beneficial manner, divided by the total monthly volume of associated gas produced by the operator. The operator is allowed to remove the initial 14 days of flowback gas in the total monthly volume calculation. The Commission will accept compliance with the gas capture goals by well, field, county, or statewide by operator. If such gas capture percentage is not attained at maximum efficient rate, the well(s) shall be restricted to 200 barrels of oil per day if at least 60% of the monthly volume of associated gas produced from the well is captured, otherwise oil production from such wells shall not exceed 100 barrels of oil per day.

The Commission will recognize the following as surplus gas being utilized in a beneficial manner:

a. Equipped with an electrical generator that consumes surplus gas from the well;
b. Equipped with a system that intakes the surplus gas and natural gas liquids volume from the well for beneficial consumption by means of compression to liquid for use as fuel, transport to a processing facility, production of petrochemicals or fertilizer, conversion to liquid fuels, separating and collecting the propane and heavier hydrocarbons; and
c. Equipped with other value-added processes as approved by the Director which reduce the volume or intensity of the flare by more than 60%.

(5) If the flaring of gas produced with crude oil from a Bakken, Bakken/Three Forks, and/or Three Forks Pool is determined by the North Dakota Department of Health as causing a

violation of the North Dakota Air Pollution Control Rules (North Dakota Administrative Code Article 33-15), production from the respective pool may be further restricted.

(6) This order shall remain in full force and effect until further order of the Commission.

Dated this 1st day of July, 2014.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Jack Dalrymple, Governor

/s/ Wayne Stenehjem, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

Oil and Gas Division

Lynn D. Helms - Director Bruce E. Hicks - Assistant Director
Department of Mineral Resources
Lynn D. Helms - Director
North Dakota Industrial Commission
www.dmr.nd.gov/oilgas/

North Dakota Industrial Commission Order 24665
Frequently Asked Questions Version 112018

Question: If an operator is granted a force majeure can that volume be counted as a gas credit?

Answer: No, force majeure gas cannot be counted as a capture credit because the gas was not physically captured.

Question: The policy states the operator is allowed to remove (from the total monthly volume calculation) gas volumes flared from wells affected by a force majeure event. If an operator's application, for removal of such gas is granted, does that gas volume have to be reported to the Commission?

Answer: Yes, all gas must be reported and accounted for on the Gas Production Report – Form 5B and the force majeure calculation adjustment will be applied during the Commission's gas capture review.

Question: The policy states the operator is allowed to remove 46 days of initial production test gas (subsequent to the initial 14 days of flowback gas) from the total monthly volume **calculation**. Does an operator have to report any gas to the Commission during the 60-day period?

Answer: Yes, all gas must be reported and accounted for on the Gas Production Report – Form 5B.

Question: Is it possible an operator could have a higher gas capture percentage than that calculated by the Commission for a particular month?

Answer: Yes, the Commission will calculate an operator's monthly gas capture percentage by examining all gas reported by the operator on the Gas Production Report – Form 5B. If this calculation confirms the operator has achieved the Commission's gas capture goal, no further analysis is performed, even though a higher gas capture percentage might be calculated if consideration was given to the initial 60 days of production and force majeure events.

Question: Are there any limitations to using accumulated gas credits to meet the monthly gas capture target goal?

Answer: Yes, Commission approval to use gas credits will only be granted if one of the following extenuating circumstances exist: (1) right-of-way issues, (2) temporary midstream down-time for system upgrades and/or maintenance, (3) federal regulatory restrictions or delays, (4) safety issues, (5) delayed access to electrical power, and (6) possible reservoir damage.

Question: Will the changes outlined in the North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 increase flaring?

Answer: No, the gas capture goals previously set by the Commission remain unchanged; therefore all operators are required to meet gas capture goals previously set by the Commission. The Commission believes the changes will allow operators, gas gathering companies, and regulators to focus resources on areas where the gas capture goals are not being met. This will allow operators and gas gathering companies to better predict future gas reserves, which will result in the construction of economic infrastructure to capture gas that would otherwise be flared.

Question: If a well is producing at or below the restriction levels stated within the order are there further restrictions?

Answer: If an operator hasn't met the gas capture requirements, but the well(s) are currently producing at the allowed barrels of oil per day as stated in the order, further restrictions will not be imposed. However, each well cannot produce over its restricted amount until it meets the target goal.

Oil and Gas Division

Lynn D. Helms - Director   Bruce E. Hicks - Assistant Director

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.dmr.nd.gov/oilgas/

The following fields fall within the Core Area referenced in the attached North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018:

Alger
Alkali Creek
Antelope
Arnegard
Avoca
Bailey
Baker
Banks
Bear Creek
Bear Den
Beaver Lodge
Big Bend
Big Gulch
Blue Buttes
Brooklyn
Bully
Camel Butte
Camp
Capa
Catwalk
Cedar Coulee
Charlson
Cherry Creek
Chimney Butte
Clarks Creek
Clear Creek
Corral Creek
Cow Creek
Crazy Man Creek
Croff
Dimmick Lake
Dollar Joe
Eagle Nest
Edge
Elidah
Ellsworth
Elm Tree
Epping
Fancy Buttes
Four Bears
Garden
Grail
Grinnell
Hawkeye
Haystack Butte
Heart Butte
Hofflund
Jim Creek
Johnson Corner
Juniper
Keene
Killdeer
Last Chance
Lone Butte
Long Creek
Lost Bridge
Mandaree
Manitou
McGregory Buttes
Missouri Ridge
Moccasin Creek
North Fork
North Tobacco Garden
Oakdale
Parshall
Patent Gate
Pembroke
Pershing
Phelps Bay
Pleasant Hill
Poe
Rattlesnake Point
Reunion Bay
Robinson Lake
Sakakawea
Sand Creek
Sandrocks
Sanish
Siverston
South Fork
South Tobacco Garden
Spotted Horn
Spring Creek
Springbrook
Squaw Creek
Stanley
Stockyard Creek
Stony Creek
Timber Creek
Tobacco Garden
Todd
Truax
Twin Buttes
Twin Valley
Union Center
Van Hook
West Capa
Westberg
Williston
Willow Creek
Wolf Bay

600 E Boulevard Ave - Dept 405, Bismarck, North Dakota 58505-0840 Phone (701)328-8020 Fax (701)328-8022

North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018

Policy Goals:

1) Increase the volume of captured gas and reduce the percentage of flared gas
2) Incentivize investment in gas capture infrastructure

Action items:

1) Require a sworn affidavit that operator has provided Gas Production Forecast data to midstream gas gathering companies and developed a Gas Capture Plan for increased density, temporary spacing, and proper spacing cases
2) Require Gas Capture Plans for all applications for a permit to drill filed by an operator who has failed to meet gas capture goals in any of the most recent three months
3) Semi-annual meetings with midstream gas gathering companies
4) Semi-annual Gas Capture Improvement Plan meetings with operators who have failed to meet gas capture goals three or more of the most recent six months
5) Annual review of gas capture goals, gas capture progress, and extenuating circumstances to be presented by Department of Mineral Resources each December
6) Track flaring on/off the Fort Berthold Indian Reservation
7) Report capture status versus goals
8) Support federal efforts to streamline right-of-way process
9) Support efforts to encourage investment in value-added projects

The initial horizontal well drilled in each spacing unit should be allowed to produce at its maximum efficient rate, regardless if the well is connected to a gas gathering system. An operator may make application to designate gas produced from up to six horizontal wells drilled in a previously undrilled governmental township or in a governmental township outside the Bakken core area as stranded gas. Wells designated as producing stranded gas should be allowed to produce at maximum efficient rate and the operator should be allowed to remove twelve months of gas production from each stranded gas well from the total monthly volume calculation. Allowing such wells to produce at a maximum efficient rate will allow valuable information to be obtained in order to make decisions regarding future well and infrastructure requirements in the spacing unit.

Commission production records indicate the majority of gas flared in North Dakota is from wells already connected to a gas gathering system. Such wells should not be excluded from gas capture goals adopted by the Commission.

Well payout and economics should not be used to determine production restrictions.

Some flared gas contains components that if improperly combusted could cause air quality degradation and health issues.

On the Fort Berthold Indian Reservation, many Bakken Pools are also within the jurisdiction of the Mandan Hidatsa and Arikara (MHA) Nation and Bureau of Land Management (BLM). In some cases, companies must comply with MHA Nation, BLM, and Commission rules. The Commission should work with federal and tribal authorities to ensure that restrictions imposed herein minimize duplication, provide clarity, and protect the correlative rights of all owners in the respective jurisdictions.

The Commission establishes the following gas capture goals:

74% October 1, 2014 through December 31, 2014
77% January 1, 2015 through March 31, 2016
80% April 1, 2016 through October 31, 2016
85% November 1, 2016 through October 31, 2018
88% November 1, 2018 through October 31, 2020
91% beginning November 1, 2020

The gas capture percentage is calculated by summing monthly gas sold plus monthly gas used on lease plus monthly gas processed in a Commission approved beneficial manner, divided by the total monthly volume of associated gas produced.

In order to allow operators the maximum flexibility to manage their drilling, operation, and gas capture plans within the gas capture goals established by the Commission, the Commission will evaluate compliance with the gas capture goals statewide, by county, by field, then by well for each operator.

1) All infill horizontal wells, including overlapping spacing units, completed in a Bakken, Bakken/Three Forks, and/or Three Forks Pool are allowed to produce at a maximum efficient rate for 90 days.
2) The operator is allowed to remove the initial 14 days of flowback gas from the total monthly volume calculation.
3) The operator is allowed to remove 46 days of initial production test gas (subsequent to the initial 14 days of flowback gas) from the total monthly volume calculation.
4) The operator is allowed to remove from the total monthly volume calculation gas volumes flared from wells already drilled and completed on the date a force majeure event occurs if the event is properly documented in writing by the gas gathering company.
5) The operator is allowed to remove from the monthly volume calculation gas volumes flared from wells already drilled and completed, if gas gathering and processing capacity curtailment is properly documented in writing.
6) The operator is allowed to remove from the monthly volume calculation gas volumes flared from wells already drilled and completed, if it can be properly documented that such gas flaring was the result of newly completed wells being connected to the same gas infrastructure system.
7) The operator is allowed to remove from the monthly volume calculation gas volumes flared from wells already drilled and completed, if the following circumstances are properly documented in writing:
   a. surface landowner, tribal, or federal government right-of-way delays
   b. temporary midstream down-time for system upgrades and/or maintenance
   c. federal regulatory restrictions or delays
   d. safety issues
   e. delayed access to electrical power
   f. possible reservoir damage
8) The operator is allowed to remove from the monthly volume calculation gas volumes placed into geologic storage or utilized in an enhanced oil recovery project, if properly documented.
9) An operator is allowed to accumulate credits for LNG utilization, CNG utilization, and volumes of gas captured during the most recent six months in excess of the current gas capture goal.
   a. The commission may apply all or a portion of the credit to a month in which the operator cannot meet the current gas capture goal upon application by the operator.
   b. Credits cannot be transferred to another operator.
   c. Unused credits expire after six months.

   d. Credits may be applied only if one or more of the extenuating circumstances exist.

10) The Commission recognizes the following as surplus gas being utilized in a beneficial manner that may be considered as captured gas:
    a. Equipping the well(s) with an electrical generator that consumes surplus gas
    b. Equipping the well(s) with a system that intakes the surplus gas and natural gas liquids volume from the well for beneficial consumption by means of compression to liquid for use as fuel, transport to a processing facility, production of petrochemicals or fertilizer, conversion to liquid fuels, separating and collecting the propane and heavier hydrocarbons.
    c. Equipping the well(s) with other value-added processes as approved by the Director which reduce the volume or intensity of the flare by more than 60%.

If an operator is unable to attain the Commission's gas capture goals at maximum efficient rate, well(s) will be restricted to 200 barrels of oil per day if at least 60% of the monthly volume of associated gas produced from the well is captured, otherwise oil production from such wells shall not exceed 100 barrels of oil per day.

Flexibility in the form of temporary exemptions from production restrictions may be considered for other types of extenuating circumstances after notice and hearing if the effect of such flexibility is a significant net increase in gas capture within one year of the date such relief is granted.

<u>Penalty provisions:</u>

Production and flaring data is two months old when filed (Example: Jan 2014 data filed Mar 2014) and data is frequently amended.

Timely communication between operators and midstream companies as well as with the Commission is of the essence. Lack of compliance with the following requirements will be considered violations:

1) Failure to file an application for hearing with the Commission within the month following the month in which the operator was unable to attain the Commission's gas capture goals and oil production exceeded production restrictions may result in a civil penalty of $1,000 per month up to a maximum of $12,500 per month beginning at $1,000 the first month and doubling each additional month that the operator is in violation.

2) Failure to implement production restrictions within the month following the month in which the operator was notified by Commission staff that gas capture goals were not attained and oil production from listed well(s) is to be restricted will result in a verbal notice of violation. The Commission will issue a written notice of violation with a compliance deadline if an operator fails to implement production restrictions for a second month. A third month in violation of production restrictions may result in a civil penalty of up to $12,500 per well for each day the well has been in violation.

OCD Exhibit 16

Oil and Gas Division

Lynn D. Helms - Director Bruce E. Hicks - Assistant Director

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.oilgas.nd.gov

September 16, 2014

RE: **GAS CAPTURE PLAN**
REQUIRED HEARING EXHIBIT

To all Hearing Applicants:

Note this letter is a revision to the Commission's previous Gas Capture Plan letter dated May 15, 2014.

Please be aware that a Gas Capture Plan (GCP) must be submitted as an exhibit at all hearings in which you intend to drill additional wells in the Bakken-Three Forks Petroleum System effective June 25, 2014. The plan is part of the North Dakota Industrial Commission's new policy on reducing gas flaring, adopted by the Commission on March 3, 2014 and with Commission Order No. 24665.

The gas capture plan must contain the following information:

1. A statement made by a company representative indicating:
    a. The name of the gas gatherer(s) the company met with.
    b. That the company supplied the gas gatherer(s) with the following information:
        i. Anticipated completion date of well(s).
        ii. Anticipated production rates of well(s).

2. A detailed gas gathering pipeline system location map which depicts the following information.
    a. Name and location of the destination processing plant.
    b. Name of gas gatherer and location of lines for each gas gatherer in the map vicinity.
    c. The existing gas line proposed to connect the subject well.

3. Information on the existing line, to which operator proposes to connect to, including:
    a. Maximum current daily capacity of the existing gas line.
    b. Current throughput of the existing gas line.
    c. Gas gatherer issues or expansion plans for the area (if known).

4. A detailed flowback strategy including:
    a. Anticipated date of first production.
    b. Anticipated oil and gas rates and duration. If well is on a multi-well pad, include total for all wells being completed.

5. Amount of gas applicant is currently flaring:
    a. Statewide percentage of gas flared (total gas flared/total gas produced) for existing wells producing from the Bakken petroleum system. Note the Commission's approved gas capture goals are to reduce flaring to 26% by October 1, 2014; 23% by January 1, 2015; 15% by January 1, 2016; and 10% by October 1, 2020.
    b. Fieldwide percentage of gas flared.

6. Alternatives to flaring.
    a. Explain specific alternate systems available for consideration.
    b. Detail expected flaring reductions if such plans are implemented.

The NDIC believes a concerted effort by operators in North Dakota is necessary to reduce the volume of flared gas, reduce the number of wells flaring, and reduce duration of flaring of wells, which will ultimately meet our goal to encourage and promote the development, production, and utilization of oil and gas in the state in such a manner as will prevent waste, maximize economic recovery, and fully protect the correlative rights of all owners to the end that the landowners, the royalty owners, the producers, and the general public realize the greatest possible good from these vital natural resources.

If you have any questions or comments, please contact our office.

Sincerely,

Bruce E. Hicks

OCD Exhibit 17

Oil and Gas Division

Lynn D. Helms - Director Bruce E. Hicks - Assistant Director

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.oilgas.nd.gov

October 1, 2014

RE: **APD GAS CAPTURE PLAN REQUIRED**

To all Operators:

Note this letter is a revision to the Commission's previous Gas Capture Plan (GCP) letter dated May 8, 2014.

A GCP must accompany every Application for a Permit to Drill (APD) and permit renewal request to complete any well within any target in the Bakken petroleum system. The plan is required as part of the North Dakota Industrial Commission's policy to reduce gas flaring which was adopted on March 3, 2014 and revised by Commission Order No. 24665 effective July 1, 2014.

The GCP must contain the following information:

1. An affidavit signed by a company representative indicating:
    a. The name of the gas gatherer the company met with.
    b. That the company supplied the gas gatherer with the following information:
        i. Anticipated completion date of well(s).
        ii. Anticipated production rates of well(s).

2. A detailed gas gathering pipeline system location map which depicts the following information.
    a. Name and location of the destination processing plant.
    b. Name of gas gatherer and location of lines for each gas gatherer in the map vicinity.
    c. The approximate route to connect the subject well(s) to an existing gas line.

3. Information on the existing gas gathering system, to which operator proposes to connect to, including:
    a. Maximum current daily capacity of the existing gas line or compressor.
    b. Current throughput of the existing gas line or compressor.
    c. Anticipated daily capacity of existing gas line or compressor at date of first gas sales.
    d. Anticipated throughput of existing gas line or compressor at date of first gas sales.
    e. Gas gatherer issues or expansion plans for the area.

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4. A detailed flowback strategy including:
   a. Anticipated date of first production.
   b. Anticipated oil and gas rates and duration. If well is on a multi-well pad, include total for all wells being completed.

5. Amount of gas the company is currently flaring:
   a. State-wide percentage of gas flared (total gas flared/total gas produced) for existing wells producing from the Bakken petroleum system. Note the Commission's approved gas capture goals are to reduce flaring to 26% by October 1, 2014, 23% by January 1, 2015, 15% by January 1, 2016, and 10% by October 1, 2020.
   b. Field-wide percentage of gas flared.

6. Alternatives to flaring (if the operator is not meeting the gas capture goal):
   a. Explain specific alternate systems the company is considering.
   b. Detail expected flaring reductions if such plans are implemented.

Permit consideration may be delayed or stipulations imposed if applicant is unable to timely connect the subject well(s) and alternatives to reduce the amount of flared gas will not be implemented.

The NDIC believes a concerted effort by operators in North Dakota is necessary to reduce the volume of flared gas, reduce the number of wells flaring, and reduce duration of flaring of wells, which will ultimately meet our goal to encourage and promote the development, production, and utilization of oil and gas in the state in such a manner as will prevent waste, maximize economic recovery, and fully protect the correlative rights of all owners to the end that the landowners, the royalty owners, the producers, and the general public realize the greatest possible good from these vital natural resources.

If you have any questions or comments, please contact our office.

Sincerely,

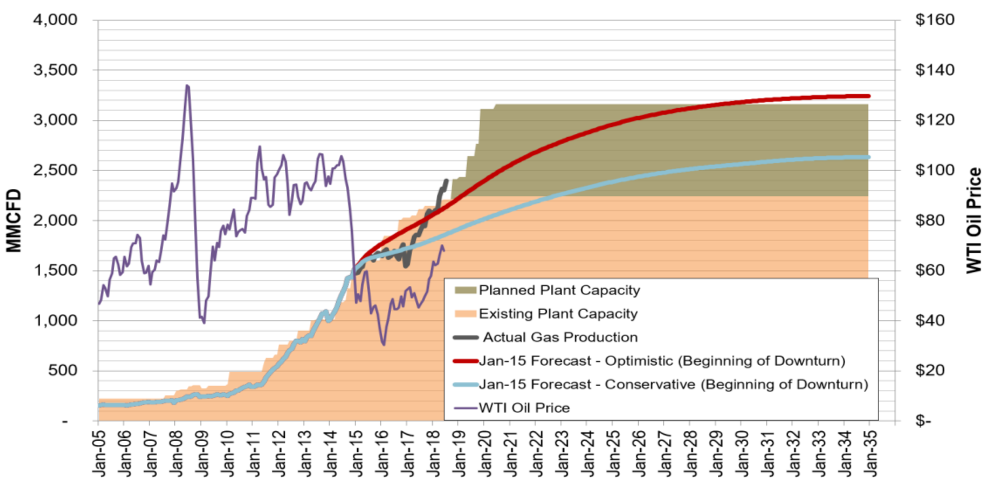
Todd L. Holweger

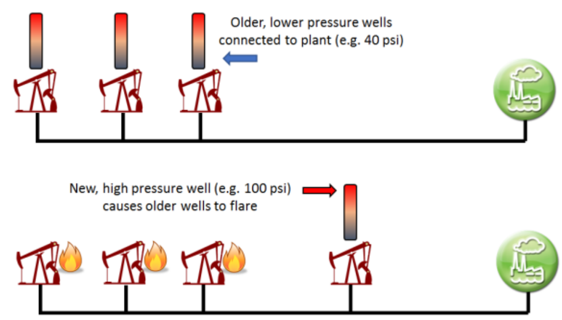
DMR Permit Manager

NORTH DAKOTA DEPARTMENT OF MINERAL RESOURCES:

OIL & GAS UPDATE

2015 NDPA Outlook vs Actual





Background:

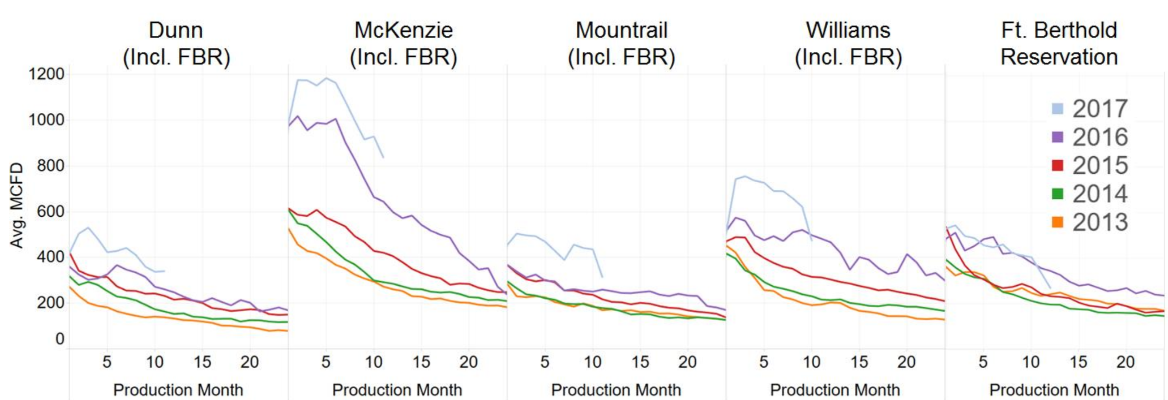
- From 2014-2017 midstream built out 1 BCFD of processing capacity following the high case projections.
- Actual gas production followed 2015 low case scenario until 2017.
- Technological innovations resulted in well performance that exceed the high case scenario 2017 and ongoing.

Ongoing Issues:

Seeing increased frequency of new high-producing wells and historically compliant wells in non-compliance due to their location on the same gathering system. Intensifying the issue includes:

- Advancements in technology: Underestimating well performance;
- Government Process: Federal right-of-way delays; and
- Location of wells: Problem occurring across western ND however increasing most in non-core areas & on Fort Berthold Reservation.

Bakken and Three Forks Well Performance



CONTACT US

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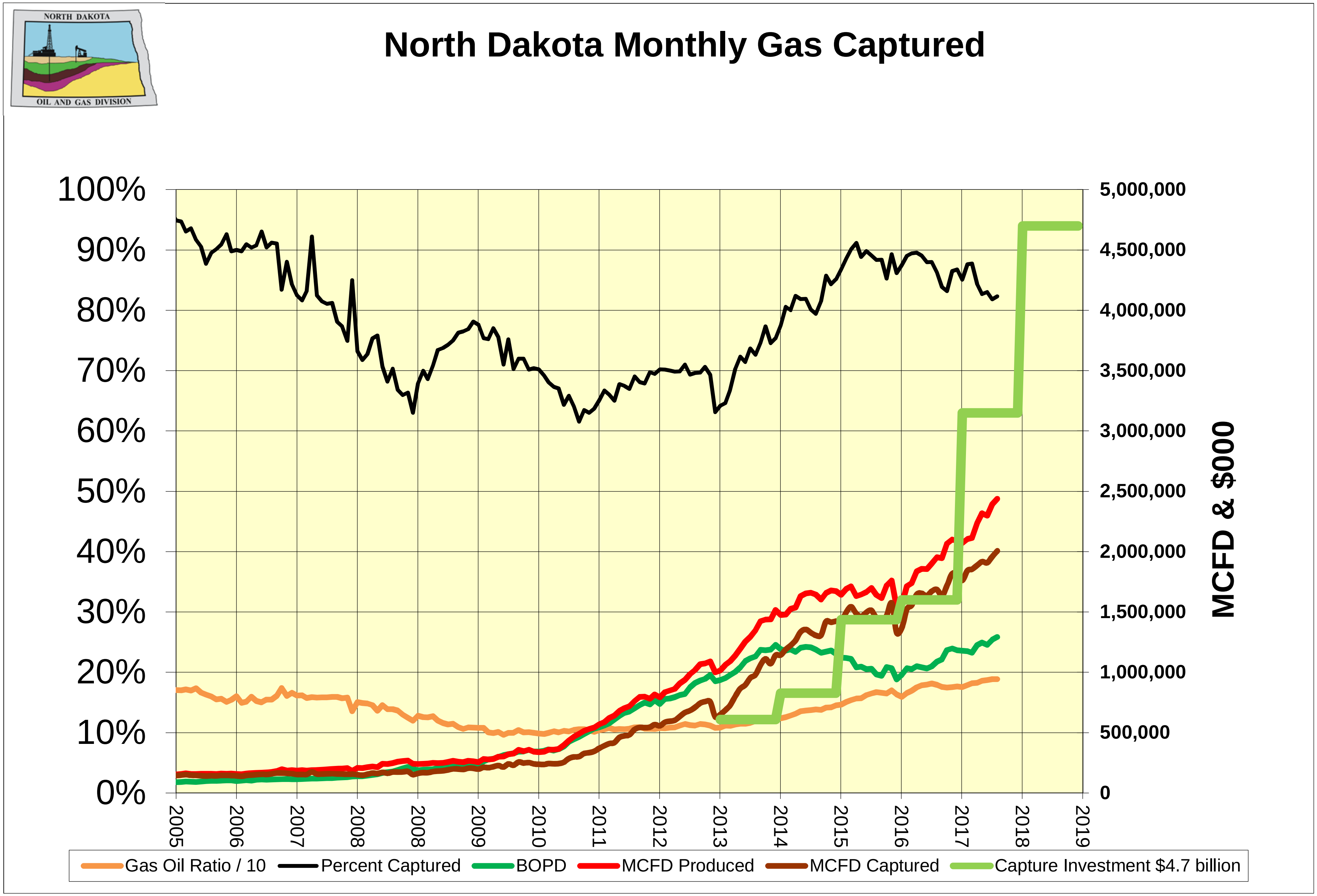
Visit Us: www.dmr.nd.gov

Source of Graphs:
North Dakota Pipeline Authority

North Dakota Monthly Gas Captured



OCD Exhibit 19

Directive 060

Release date: May 12, 2020

Effective date: May 12, 2020, unless otherwise indicated

Replaces previous edition issued December 13, 2018

Upstream Petroleum Industry Flaring, Incinerating, and Venting

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Contents

Figures

Tables

1 Introduction

1.1 Purpose of This Directive

The Alberta Energy Regulator (AER) *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* contains the requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities. *Directive 060* requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER in accordance with the *Pipeline Act*. With the exception of oil sands mining schemes and operations, *Directive 060* applies to all schemes and operations approved under section 10 of the *Oil Sands Conservation Act* (*OSCA*). *Directive 060* does not apply to any processing plants approved under section 11 of the *OSCA*.

Most of these requirements have been developed in consultation with the Clean Air Strategic Alliance (CASA) to eliminate or reduce the potential and observed impacts of these activities and to ensure that public safety concerns and environmental impacts are addressed before beginning to flare, incinerate, or vent. *Directive 060* requirements are also aligned to ensure compliance with Alberta Environment and Parks (AEP) *Alberta Ambient Air Quality Objectives and Guidelines* (*AAAQO*).

Note: Appendices have been included to further the understanding of *Directive 060* requirements. See appendix 1 for a list of references and contacts, appendix 2 for definitions of terms, and appendix 3 for abbreviations.

1.2 What's New in This Edition

The following changes related to managing methane emissions were made:

- Section 2.9.1: Included reduced carbon levies in economic evaluations of gas conservation projects.
- Section 5.5: Revised measurement and reporting requirements to ensure consistency with the definitions in appendix 2 for fuel, flare, and vent gas.
- Section 8: Amended vent gas limits for crude bitumen batteries, pneumatic devices, compressor seals, and glycol dehydrators. Also amended the exemptions for the overall vent gas limit and defined vent gas limit.

1.3 Flaring, Incineration, and Venting Management Hierarchy and Framework

Flaring, incinerating, and venting are associated with a wide range of energy development activities and operations, including disposal of gas associated with

- oil, bitumen, and gas well drilling;
- oil, bitumen, and gas well completion or well servicing (well "cleanup");
- gas well testing to estimate reserves and determine productivity;
- routine oil or bitumen production (solution gas);
- planned nonroutine depressurizing of processing equipment and gas pipelines for maintenance;
- unplanned nonroutine depressurizing of process equipment and gas pipelines due to process upsets or emergency; and
- oilfield waste management facilities.

Two multistakeholder teams from CASA have made recommendations for flaring, incineration, and venting for the upstream petroleum industry, and the AER has based this directive on those recommendations (see appendix 4 for background on *Directive 060*).

In particular, the AER has adopted CASA's objective hierarchy and its framework for managing routine solution gas flares (see figure 1) and has extended its application of the hierarchy to include flaring, incineration, and venting of gas in general.[1]

In accordance with the objective hierarchy, licensees, operators, and approval holders must evaluate the following three options:

- Can flaring, incineration, and venting be eliminated?
- Can flaring, incineration, and venting be reduced?
- Will flaring, incineration, and venting meet performance standards?

[1] See CASA's website www.casahome.org.

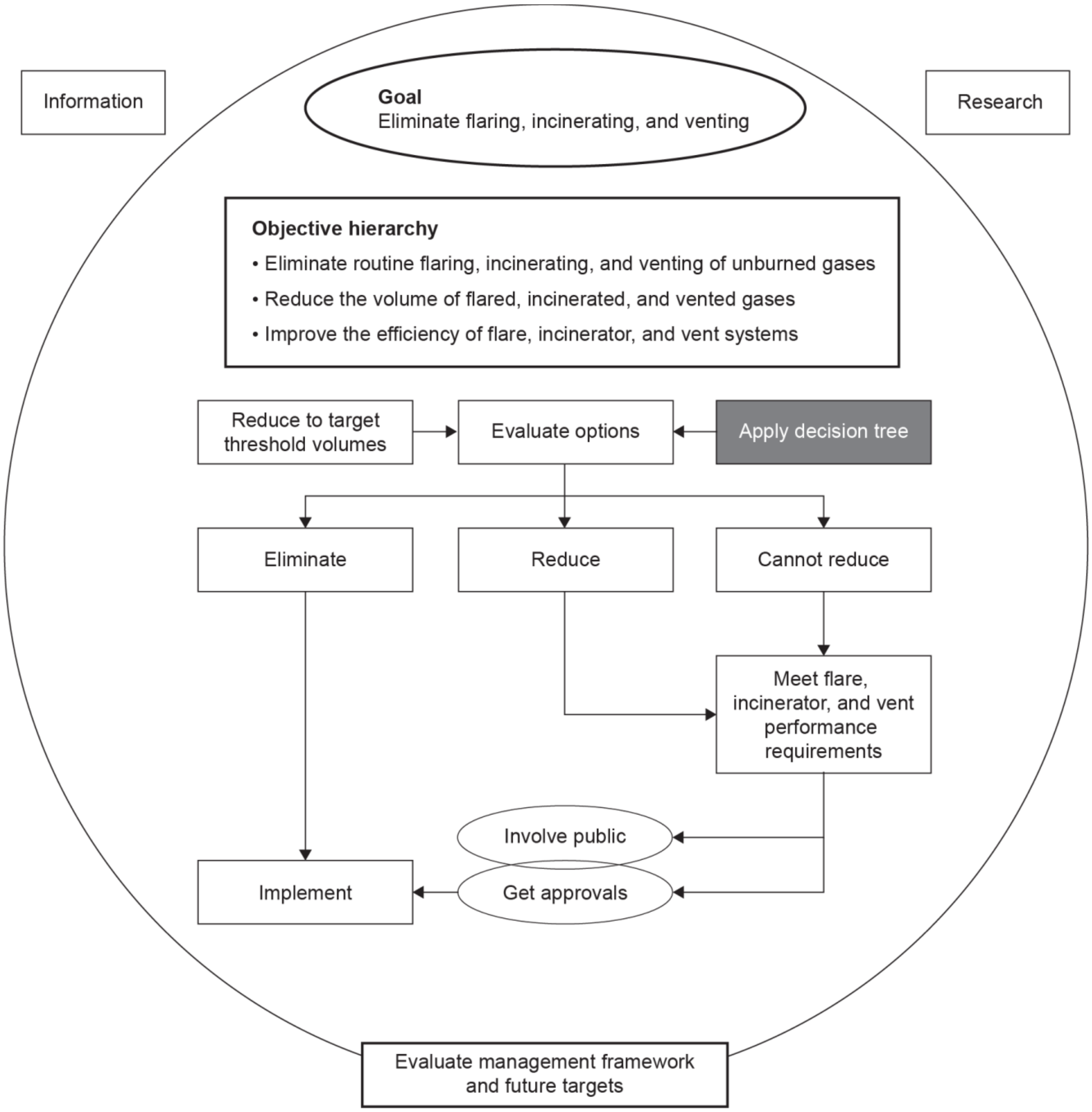

Figure 1. Solution gas flaring/venting management framework (adapted from CASA)

1.4 Access to Production Flaring, Incineration, and Venting Data

The AER reports flaring, incineration, and venting volumes annually in the *ST60B: Upstream Petroleum Industry* flaring report on the AER website www.aer.ca.

The AER also makes flaring, incineration, and venting information available to licensees, operators, and approval holders in order to facilitate solution gas conservation and clustering opportunities, as described in section 2.13.

1.5 AER Requirements

Following AER requirements is mandatory for the responsible duty holder, as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The term "must" indicates a requirement, while terms such as "recommends" and "expects" indicate a recommended practice.

Each AER requirement is numbered.

Information on compliance and enforcement can be found on the AER website.

1.6 Frequency

For the purposes of this directive, terms like annually or quarterly are defined as follows:

- Monthly is at least once per calendar month.
- Bimonthly is at least once every two consecutive calendar months.
- Quarterly means at least once per calendar quarter. Calendar quarters are January to March, April to June, July to September, and October to December.
- Triannually means at least once per four calendar months.
- Annually means at least once every four calendar quarters.

Example: If a survey needs to be done annually and the last survey occurred in May 2019 (second quarter), the operator has to perform another survey by the end of the second quarter of 2020 (June 30).

1.7 Notification Through the Designated Information Submission System

The licensee, operator, or approval holder must notify the appropriate AER field centre before planned flaring, venting, or incineration operations by completing and submitting an AER flaring/incineration/venting notice form within the designated information submission system. The AER strongly encourages all licensees, operators, and approval holders to follow the FIS Web User Guide when completing and submitting this form. Any operations that may result in a public complaint must be called in to the appropriate AER field centre's 24-hour emergency phone number (see appendix 1).

For questions on using FIS, contact the FIS administrator by email at FIS.Administrator@aer.ca or by telephone at 403-297-4845.

1.8 Review and Revision

The AER will review the methane emission requirements in this directive no later than December 31, 2022, taking into account

- the efficiency and effectiveness of the requirements in reducing methane emissions to meet the outcome of a 45 per cent decrease by 2025 relative to 2014 levels; and
- developments in practices, processes, and technologies to control methane emissions.

Based on the outcome of the review, requirements may be revised.

2 Solution Gas Management (Crude Oil / Bitumen Battery Flaring, Incineration, and Venting)

The AER's goal is to have the upstream petroleum industry continue to reduce the volume of solution gas routinely flared, incinerated, and vented. The AER expects that the upstream petroleum industry will pursue continuous improvement in reducing solution gas flaring, incineration, and venting in Alberta, and, in consultation with stakeholders, will monitor progress to determine the need for additional requirements to facilitate increased solution gas conservation.

Combustion of solution gas in incinerators is not considered an alternative to conservation.

For solution gas management and disposition reporting, incinerated gas must be reported as flared.

Conservation is defined as the recovery of solution gas for use as fuel for production facilities, for other useful purposes (e.g., power generation), for sale, or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery). Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in section 2.9.

In this section, for the "combined flared and vented volumes" the vented volumes must not exceed the vent gas limits in section 8.

2.1 Solution Gas Flaring Reduction Targets

Directive 060 incorporates recommendations made by CASA in 2002, 2004, and 2005 to reduce flaring.

1) The Alberta solution gas flaring limit is 670 million cubic metres (10^6 m^3) per year (50 per cent of the revised 1996 baseline of 1340 10^6 m^3/year).
2) If solution gas flaring exceeds the 670 10^6 m^3 limit in any year, the AER will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than 670 10^6 m^3/year. For example, solution gas flaring could be limited to a maximum of 500 thousand (10^3) m^3/year at any one site.

2.2 Solution Gas Venting Reduction

The AER does not consider venting an acceptable alternative to flaring. If venting is the only feasible alternative, the requirements in section 8 must be met.

In 2005, 59 per cent less solution gas was vented than in 2000. The CASA Flaring and Venting Project Team considered solution gas venting in the report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project*

Team, which it released in 2004.[2] The AER accepts these recommendations and has incorporated them into *Directive 060*.

2.3 Solution Gas Flaring and Venting Decision Tree

The AER adopted the solution gas flaring/venting management framework (figure 1) and endorses the solution gas flaring and venting decision tree process (figure 2) as recommended by CASA. The licensee or operator must apply this decision tree to combined flaring and venting of more than 900 m^3/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

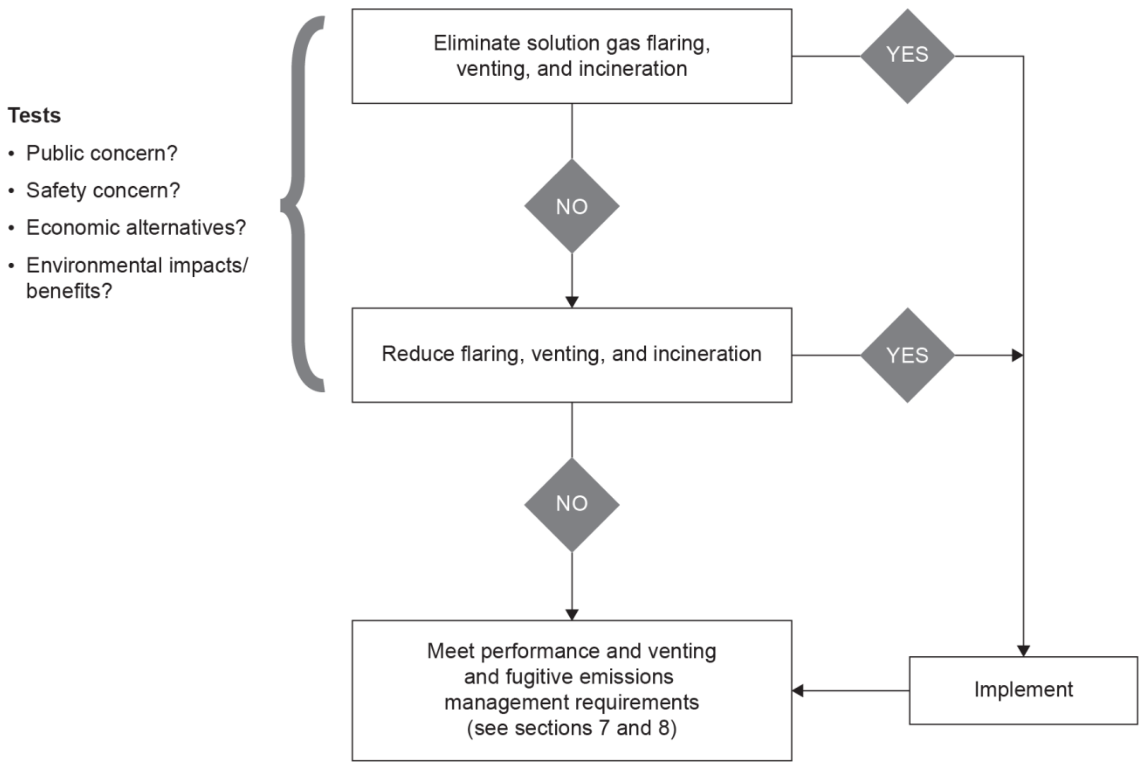

Figure 2. Solution gas flaring/venting decision tree (adapted from CASA)

2.4 Conservation at Crude Bitumen Batteries

For the purpose of *Directive 060*, crude bitumen battery is defined in appendix 2.

1) The licensee or operator of a multiwell bitumen site must build solution gas conservation lines to one common point on the lease as part of initial construction.

2) For new bitumen wells, the test period (excluding completion and cleanup operations) limit is either six months or until combined flared and vented volumes at the site exceed a rolling average of 900 m^3/day for any consecutive three-month period, whichever is less.

[2] This and other reports from this team are available on CASA's website, www.casahome.org.

a) As soon as testing shows that combined flaring and venting volumes at the site exceed 900 m^3/day, conservation must be evaluated as described in section 2.9. Volumes are calculated based on a three-month rolling average.

b) If conservation is required, it must occur as quickly as possible and must not extend for more than six months after flow-rate determination. Shorter tie-in times must be pursued wherever possible. Wells must be shut in if the required conservation is not operational within the timelines noted above.

3) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m^3/day, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The AER, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m^3/day.

4) The vent gas volumes from testing must not exceed the vent gas limits specified in section 8.

2.5 Conservation at Conventional Crude Oil Batteries

For the purpose of *Directive 060*, crude oil battery is defined in appendix 2.

In general, for new oil wells the solution gas flaring during the test period must not extend beyond the time required to obtain data for the economic evaluation and for sizing conservation equipment. Any flaring for testing, cleanup, and completions must not exceed 72 hours (see section 3.2 for further details and extensions to time limits).

1) Upon completion of the testing period, if testing shows that combined flaring and venting volumes at the site will exceed 900 m^3/day, solution gas conservation must be evaluated as described in section 2.9. The wells must be shut in at the end of the test period and remain shut in pending the results of the solution gas conservation evaluation process.

   a) If the results of the solution gas conservation evaluation indicate that conservation is required, the wells must remain shut in until conservation is implemented.

   b) If the results of the solution gas conservation evaluation indicate that conservation is not required and the AER has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas.

2) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m^3/day and the AER has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas. The AER, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m^3/day.

3) The vent gas volumes from testing must not exceed the vent gas limits specified in section 8.

2.6 General Conservation Requirements at all Condensate Producing Sites and Crude Oil and Crude Bitumen Batteries

These requirements apply to all condensate producing sites and crude oil and crude bitumen batteries unless otherwise specified.

1) The licensee or operator must conserve solution gas at all sites[3] where
   a) the combined flaring and venting volume is greater than 900 m^3/day per site[4] and the decision tree process and economic evaluation (see section 2.8) result in a net present value (NPV) greater than –Cdn$55 000;
   b) the gas:oil ratio (GOR) is greater than 3000 m^3/m^3. All wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well must be shut in until the gas is conserved;
   c) flared or incinerated volumes are greater than 900 m^3/day per site and the flare or incinerator is within 500 m of a residence, regardless of economics; or
   d) the AER directs the licensee, operator, or approval holder to conserve solution gas, regardless of economics.
2) For any sites with a combined volume of flaring and venting that is greater than 900 m^3/day and that are not conserving, an economic evaluation must be completed every 12 months using the criteria in section 2.9.
3) The AER may still, on a case-by-case basis, require economic evaluations for sites that have a combined volume of flaring and venting of less than 900 m^3/day and that are not conserving if it is believed that conservation may be feasible.
4) Conserving facilities must be designed for 95 per cent conservation with a minimum operating level of 90 per cent.
5) The licensee or operator may apply to discontinue conservation if annual operating expenses exceed annual revenue. See section 2.6(6).
6) The licensee or operator must get approval from the AER Authorizations Branch to discontinue conservation once it has been implemented at any facility, and must
   a) complete a decision tree to evaluate alternatives to discontinuing conservation,
   b) provide information on actual annual operating expenses and revenues,
   c) notify the appropriate AER field centre and residents within 500 m of its intention to discontinue conservation and initiate flaring or venting at a site, and

[3] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.
[4] Volumes are calculated based on a three-month rolling average.

d) if conservation facilities are not operational, comply with table 1 until such time as approval from the AER Authorizations Branch to discontinue conservation is granted.

2.7 Clustering

Clustering is defined as the practice of gathering the solution gas from several flares or vents at a common point for conservation. Solution gas is economic to conserve in some areas if licensees and operators coordinate their efforts in an efficient, cooperative process to take advantage of combined gas volumes and economies of scale. Furthermore, solution gas conservation economics (see section 2.9) will be enhanced if conservation is incorporated into the initial planning of larger multiwell projects.

1) Licensees or operators of active production facilities operating within three kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must evaluate clustering when evaluating solution gas conservation economics.

The AER may suspend production in the area under consideration until the economic assessment is complete.

The AER recommends that

- all licensees and operators exchange production data and jointly consider clustering of solution gas production or regional gas conservation systems, and
- the licensee or operator with the largest flare and vent volumes take the lead in coordinating the evaluation of conservation economics for the area.

2) The licensee or operator of a multiwell oil or bitumen development must assess conservation on a project or development area basis regardless of distance. Evaluations must address all potential gas vent and flare sources associated with the multiwell development.

   a) The licensee or operator must incorporate provision for conservation at all stages of project development to optimize the opportunity for economic conservation of solution gas.

   b) Applications under *Directive 056: Energy Development Applications and Schedules* for multiwell oil or bitumen developments must include a summary of the gas conservation evaluation and a description of the licensee or operator's related project plans.

The AER may suspend production at any facility until the economic assessment is complete.

2.8 Power Generation Using Otherwise-Flared/Vented Gas

Power generation is a means of conserving solution gas. The operator or licensee should consider power generation if distribution lines are nearby or if on-site power is required. The AER may investigate flared and vented volumes as low as 500 m^3/day if it appears that gas is stable.

1) Approval of electrical power plants by the Alberta Utilities Commission is required under the *Hydro and Electric Energy Act*.

   Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations provides application requirements for power plant applications and includes a simplified application form for electric power generating projects of 1.0 megawatt (MW) or smaller.

2) Power plants with a generation capacity greater than 1.0 MW at peak load require approval issued by AEP under the *Environmental Protection and Enhancement Act* (*EPEA*).

2.9 Economic Evaluation of Gas Conservation

If conservation is determined to be economic by any method using the economic decision tree process, the gas must be conserved.

1) Methods of conservation must include pipeline to sales, fuel, power generation, pressure maintenance, or any other method that may become available.

2) Licensees or operators must update the conservation economics for any sites that are flaring or venting combined volumes of more than 900 m^3/day and that are not conserving every 12 months. This information, with the responsible individual named and the document dated, is to be kept on file by the licensee or operator and must be provided to the AER upon request. Evaluation information may be stored at a central location rather than on site.

3) A licensee or operator must provide the evaluation to the AER within five working days of receipt of a request.

4) A licensee must complete the economical evaluation process in accordance with *Directive 060* requirements.

2.9.1 Economic Evaluation Criteria

Economic evaluations of gas conservation must use the criteria listed below. The licensee or operator must consider the most economically feasible option in providing detailed economics. Specific AER economic evaluation submission requirements are listed in section 2.9.2.

1) Evaluations must be completed on a before-tax basis, and must exclude contingency and overhead costs.

2) Conservation economics must be evaluated on a royalties-in basis (paying royalties) for incremental gas and gas by-products that would otherwise be flared or vented. If the economic evaluation results in an NPV less than –Cdn$55 000, the licensee or operator must re-evaluate the gas conservation project on a royalties-out basis (not paying royalties). If the evaluation results in an NPV –Cdn$55 000 or more, the licensee or operator must proceed with the

conservation project and may then apply to Alberta Energy for an "otherwise flared solution gas" royalty waiver.

3) Price forecasts used in the evaluation of solution gas conservation projects (gas gathered, processed, and sold to market) must use the most recent version of commodity price forecast from GLJ Petroleum Consultants Limited. Gas prices must be obtained from the "Natural Gas and Sulphur Price Forecast Table" in the "ARP" column ($Cdn/MMBtu). Condensate prices must be obtained from the "Crude Oil and Natural Gas Liquids Table" in the "Alberta Natural Gas Liquids Section – Edmonton Pentanes Plus" column ($Cdn/bbl).

4) Price forecasts for power generation projects must reflect the most recent 12-month rolling average of the pool monthly summary price as published by the Alberta Electric System Operator (AESO).[5] The power price must be escalated at the long-term inflation rate (see item 9). Alternatively, the cost of the power displaced at the site may be used.

5) The licensee or operator must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes). The production forecast must be reviewed by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.[6]

6) The licensee or operator must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers based on selection of appropriate technology. Any capital costs incurred before the initiation of the solution gas project (i.e., sunk costs) must not be included in the analysis; only future capital costs related to solution gas conservation may be included.

   a) For new flares, if capital cost savings result from implementing gas conservation, such as any equipment that would otherwise be required, the flares must be considered in the conservation economic evaluation and subtracted from the overall cost of the conservation infrastructure in evaluating the economics of solution gas tie-in.

   b) Salvage value of gas conservation infrastructure must be included as project revenue in the year the value would be realized (e.g., transfer of a gas compressor from one conservation project at the end of that project's life to another conservation project). The salvage value must be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective.

7) The incremental annual operating costs for the gas conservation project, including gas gathering and processing fees, are to be assumed as up to 10 per cent of the initial capital cost of installing the conservation facilities. If the gas contains 10 moles per kilomole (mol/kmol) hydrogen sulphide (H_2S) or more, the incremental annual operating costs for the solution gas

[5] The most recent 12-month rolling average of the pool monthly summary price can be found on the AESO website at http://ets.aeso.ca.

[6] *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

project may be assumed to be up to 20 per cent of the capital cost to initially install the conservation facilities.

a) The economic evaluation must account for any cost savings, such as reduced costs for trucking or equipment rental and reduced carbon levies.

8) The incremental annual operating costs for power generation projects are to be assumed as up to 10 per cent of the initial capital cost of installing the generation facilities. Standby fees may be calculated in addition to this 10 per cent allowance.

9) The most recent inflation rate must be based on the current economic trends report published quarterly on the Government of Alberta, Treasury Board and Finance, Economy and Statistics website.

10) The discount rate must be equal to the prime lending rate of ATB Financial on loans payable in Canadian dollars plus 3 per cent, based on the month preceding the month the evaluation was conducted in. This rate is reviewed periodically by the AER and will be revised if the cost of capital for the oil and gas industry changes significantly.

11) A solution gas conservation project is considered economic, and the gas must be conserved, if the economics of gas conservation generates an NPV before-tax of more than –Cdn$55 000.

    a) The NPV is defined as the sum of discounted, annual, before-tax cash flows for the economic life of the solution gas conservation project, where each annual before-tax cash flow is net of that year's conserving project capital investment, if any.

    b) The economic life of a conservation project is defined as the period from the start of the project to the time when annual expenses exceed annual revenue. Note that section 2.6(6) provides a process whereby the licensee or operator may apply to discontinue conservation if annual expenses exceed annual revenue.

12) If a solution gas conservation project has an NPV less than –Cdn$55 000 and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually (within 12 months of the latest evaluation) using updated prices, costs, and forecasts.

2.9.2 AER Economic Evaluation Audit Requirements

1) Economic evaluation audit packages submitted to the AER Authorizations Branch upon request must contain the following information in SI (international system of units) units:

    a) detailed capital and operating cost schedules as set out in sections 2.9.1(6) and 2.9.1(7)

    b) oil and gas reserves calculations and supporting information (including a discussion of planned drilling programs and pressure maintenance schemes)

c) a production forecast for both the oil and gas streams and the economic limit (date and production rates) of the project based on the oil production rate (including planned drilling programs and pressure maintenance schemes)

d) a copy of the gas analysis from the project or a representative analog complete with gas heating value and gas liquid yields

e) documentation of alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation

f) documentation of compliance with the requirements listed in sections 7 and 8

2.10 Public Involvement

Licensees or operators with continuous solution gas flares, incinerators, or vents are expected to respond to questions or concerns raised by the public in relation to activities related to the flaring, incineration, and venting of solution gas at upstream petroleum industry facilities. To help respond to the public, public information packages should be prepared and provided. Licensees or operators must also meet consultation and notification requirements in *Directive 056*.

1) The licensee or operator must notify residents, schools, and the appropriate AER field centre of nonroutine flaring, incineration, and venting at production and processing facilities, as described in section 2.11, table 1.

2) The licensee or operator must meet minimum spacing requirements (see section 7.8).

2.10.1 Public Information Package

As a minimum, public information packages should include the following:

1) the definition of solution gas, and information on its conservation and use

2) an explanation of solution gas flaring, incineration, and venting management options and the decision tree process

3) a summary of analysis completed to determine that flaring, incineration, or venting is needed

4) information on general flare/vent performance requirements and reduction targets

5) descriptions of specific actions the licensee or operator will take to eliminate or reduce flaring, incineration, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation

6) a list of industry, AER, and government contacts that are related to public consultation and relevant to the project

2.11 Nonroutine Flaring, Incineration, and Venting at Solution Gas Conserving Facilities

The licensee or operator must minimize nonroutine flaring, incineration, and venting during upsets and outages of solution gas conserving facilities.

The AER also recommends that the licensee or operator contact the appropriate AER field centre for recommendations for minimizing solution gas flaring during outages at conserving facilities.

2.11.1 Limitations on Nonroutine Flaring, Incineration, and Venting During Outages at Solution Gas Conserving Facilities

1) Production operations must be managed to control nonroutine flaring, incineration, and venting of normally conserved solution gas in accordance with table 1 below.
2) Table 1 does not apply to nonassociated gas (the percentage cutbacks listed in table 1 apply to solution gas only). All nonassociated gas must be shut in during facility outages.
3) Emergency or plant upset shut in of production and reduction of solution gas inlet requirements in table 1 do not apply to thermal in situ production.
4) The licensee or operator must provide notification as required in table 1.
5) If there is a restriction to the plant inlet, the AER recommends that solution gas processing have priority over the processing of nonassociated gas in order to limit the unnecessary flaring of solution gas.
6) The AER recommends that wells with the highest GOR be the first to be shut in during facility outages and cutbacks.
7) Provided the overall required percentage reduction in solution gas production is achieved, it is not necessary to implement equal reductions at all locations upstream of the conserving facility outage.
    a) When multiple licensees or operators are involved, they may determine how to best implement the overall required production reductions. If an agreement cannot be reached, each licensee and/or operator must reduce production as specified in table 1.

Table 1. Limitations and notification requirements for nonroutine flaring, incinerating, and venting during solution gas conserving facility[1] outage

Shutdown category	Duration	Operational requirements
Partial equipment outages	< 5 days	Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank -top gas, shut-in of production is not required for equipment outages lasting less than 5 days that involve small volumes of gas (e.g., storage tank vapour recovery unit repair). This allowance is limited to a maximum of $2.0\ 10^3\ m^3$ per day subject to limitation on venting as defined in section 8. If the event is ≥5 days, the operator must meet requirements stated below (planned shutdown category, >4 hours duration).
Planned	< 4 hours	The licensee or operator must make all reasonable efforts[2] to reduce battery or solution gas plant inlet gas volumes by 50 per cent of average daily solution gas production over the preceding 30-day period.
	> 4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily solution gas production, a variance must be obtained from the appropriate AER field centre (see section 2.11.3). • Residents within 500 m must be notified[3] at least 24 hours before the planned flaring event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre must be notified[4] 24 to 72 hours in advance if the event meets reporting requirements identified in *IL 98-01*,[4] section 4.4.
Emergency[6] or plant upset	< 4 hours	No reduction in the plant inlet is required.
	> 4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily production, a variance must be obtained from the appropriate AER field centre (see section 2.11.3). • Residents within 500 m must be notified[4] without delay about the flaring event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre[3] must be notified without delay if the event meets reporting requirements identified in *IL 98-01*,[5] section 4.4.
Repeat nonroutine flaring[7]		The licensee or operator must investigate causes of repeat nonroutine flaring or venting and take steps to eliminate or reduce the frequency of such incidents.

1 For the definition of conserving facility, see appendix 2.

2 Notwithstanding solution gas reduction requirements listed in table 1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour *AAAQO* for sulphur dioxide (SO_2) under high flow-rate conditions, action must be taken immediately to reduce gas to a rate compliant with the *AAAQO* (see section 7.12.5).

3 The appropriate AER field centre must be notified through the designated information submission system. In situations where limits have been exceeded, the appropriate AER field centre must be contacted by telephone before the designated information submission system is notified.

4 Refer to section 3.8 (4) for resident notification requirements.

5 *IL 98-01: A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*.

6 Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that causes the nonroutine flaring at the battery.

7 Repeat nonroutine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.

2.11.2 Planned Shutdown (Turnaround) Considerations

1) A licensee or operator must evaluate and implement appropriate measures to reduce solution gas flaring, incineration, and venting during a facility turnaround or planned shutdown. Alternatives that minimize impacts of planned shutdowns include

   a) delivering solution gas to a nearby gas plant or facility that is not on turnaround;

   b) scheduling maintenance at related oil facilities to coincide with the gas plant turnaround;

   c) injecting solution gas into the gas cap of an oil pool or into a gas reservoir and producing it back when the gas plant is back on stream (see *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*); and

   d) communicating with well, battery, and gas plant licensees or operators to ensure that nonroutine solution gas flaring, incineration, and venting are minimized.

2.11.3 Alternatives to Solution Gas Shut-in Requirements

The appropriate AER field centre will consider alternatives to the shut-in requirements listed in this directive for solution gas. This will be done only if the licensee or operator can demonstrate that shutting in a well or a group of wells may cause damage to well equipment or permanent reduction in productivity or if shutting in is impractical due to the remoteness of facilities. In these special cases, the licensee or operator must consult with the AER field centre about alternatives to shut in for a particular gas plant or battery.

1) A licensee or operator must plan for outages. If an alternative to table 1 is justified, the AER recommends that the licensee or operator submit a written request to the AER field centre at least 30 days before a planned shutdown explaining the alternative requested and giving supporting reasons for the request. The AER recommends that wherever possible, contact with the AER field centre not be deferred until an actual outage occurs.

2.12 Royalty Treatment of Flared and Vented Gas

In December 1998, the Government of Alberta created the Otherwise Flared Solution Gas Royalty Waiver Program to encourage the productive use of solution gas currently being flared. For more information, see Alberta Energy *Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program* available on Alberta Energy's website www.energy.alberta.ca.[7]

[8] http://www.energy.alberta.ca/NaturalGas/1139.asp

The program is summarized as follows:

- The Alberta Department of Energy has developed criteria for ensuring that when gas can be economically conserved, it does not receive a royalty waiver.
- The program covers all methods of conserving solution gas.

2.13 Solution Gas Reporting Requirements and Data Access

2.13.1 Solution Gas Reporting Requirements

1) Flared, incinerated, and vented solution gas must be reported monthly through Petrinex (Canada's Petroleum Information Network) as described in section 10.

    a) A licensee or operator must report all new oil well production, including the test period, and obtain a battery code for any new oil wells before production, including flaring, can be reported (see *Directive 017: Measurement Requirements for Oil and Gas Operations*).

2.13.2 Cooperating with Third Parties

The AER recommends that the licensee or operator cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts by providing nonconfidential information, such as gas analyses, flared and vented volumes, pressures, and other relevant data, on a timely basis (also see section 2.7).

In cases where conservation is determined by the licensee or operator to be uneconomic (as per section 2.8) but where a third party is able to conserve the gas, the AER recommends that the licensee or operator either conserve the gas or make the gas available at the lease boundary at no charge within three months of a request for the gas. It would be understood that this gas may be provided without processing or compression, and the third party must not affect the upstream operations.

Any third party requesting data from a licensee or operator must be technically qualified and have a reasonable expectation of proceeding with the gas conservation project. Third parties must also comply with all relevant AER requirements.

3 Temporary and Well Test Flaring and Incinerating

This section applies to temporary flaring and incineration activities. These activities include well testing, well cleanup, well servicing, sour gas pipeline (as defined in *Directive 056*) blowdown, coalbed methane well testing, underbalanced drilling, maintenance blowdowns, and emergency blowdowns through temporary or permanent flare or incinerator equipment.

Unplanned nonroutine flaring and incinerating (e.g., process upsets, emergencies) do not require a temporary permit. Planned nonroutine flaring and incineration events (e.g., maintenance blowdowns, pipeline depressurizing, turnarounds) do require a temporary flaring or incineration permit, as stated in section 3.3.

The AER does not consider venting an acceptable alternative to flaring or incineration. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved. If venting is the only feasible alternative, it must meet the requirements in section 8.

3.1 Temporary Flaring and Incinerating Decision Tree

1) Licensees must use the temporary flaring and incinerating decision tree process (figure 3) to evaluate all opportunities to eliminate or reduce flaring and incineration, regardless of volume.

2) Licensees must evaluate opportunities to use existing gas gathering systems before beginning temporary maintenance, well cleanup, or testing operations (i.e., "in-line testing"). In-line testing must be done when economic and feasible to do so. Information on the evaluation of the most feasible option (e.g., closest potential tie-in location) must be provided with permit requests (section 3.5.1). The AER recommends that in-line testing be used in situations where

    a) suitable infrastructure exists in proximity to the well and can be connected at moderate cost and where use of the infrastructure does not compromise integrity, or

    b) sufficient productivity information is known about a development well so that connecting pipelines can be built with minimal financial risk before testing.

3) If in-line testing is not possible, licensees must design completions and well testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* must be consulted on the minimum pressure and deliverability requirements for well testing and on the recommended practices in order to ensure that the appropriate information is obtained for conservation and pool management purposes in addition to the requirements of this directive.

Licensees must use appropriate equipment and design temporary (maintenance, well completion, or test) programs to comply with performance requirements in section 7 and the *AAAQO*.

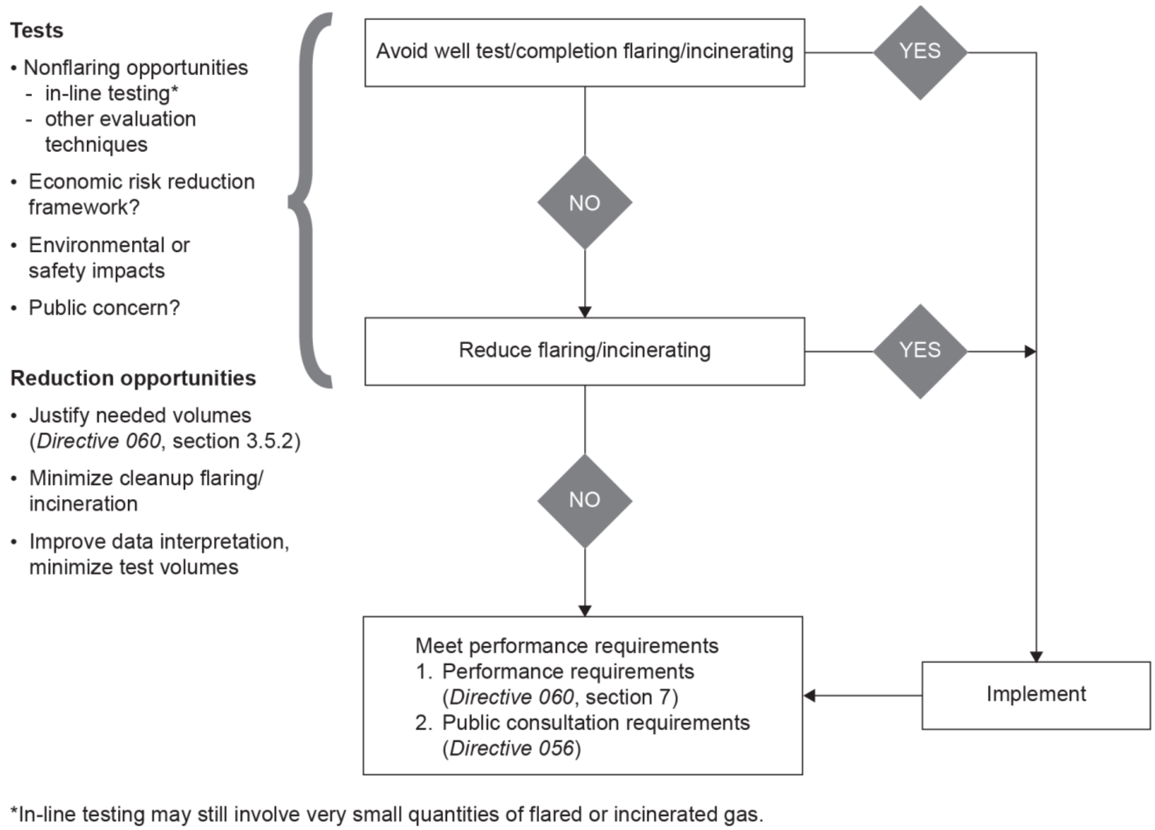

Figure 3. Temporary flaring and incineration decision tree (adapted from CASA)

3.2 Oil and Gas Well Test Flaring, Incinerating, and Venting Duration Limits

1) These time limits are per zone, are nonconsecutive, and do not include shut-in time. These periods include flaring, incinerating, and venting during cleanup, completion, workover, and testing. Licensees and operators must not exceed the following flaring, incinerating, and venting time limits:

   a) crude oil wells/sites:[8] 72 hours

   b) bitumen wells/sites: until flow rates exceed an average of 900 m^3/day for any consecutive three-month period, not to exceed six months. See section 2.4.

   c) gas (nonassociated, noncoalbed methane) wells: 72 hours

   d) dry coalbed methane development wells (producing less than 1 m^3 of water per operating day): 120 hours

   e) dry coalbed methane nondevelopment wells (producing less than 1 m^3 of water per operating day): 336 hours

   f) wet coalbed methane wells (producing more than 1 m^3 of water per operating day): see section 3.2(7) below

[8] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.

2) Extensions to the time limits listed in (1)(a), (c), (d), and (e) above are allowed if any of the following are true:

   a) Cleanup of the wellbore is not complete. Cleanup is considered complete when sand, proppant, or acid is no longer produced or when the gas composition meets the minimum pipeline specifications for the nearest pipeline that could accept the gas.

   b) Stabilized flow has not been reached. Refer to *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*, section 4.3, and *Directive 034: Gas Well Testing, Theory and Practice*, section 7.1.

   c) There have been mechanical problems with the well.

3) For extensions to the time limits stated in (1)(b) and (f), licensees must request approval from the AER as described in (5) below.

4) The licensee must document these reasons for extension and keep the information on file for review and/or audit by the AER field centre when requested. The licensee is not required to ask permission to extend the flaring/incineration beyond the specified time limit listed in (1)(a), (c), (d), or (e) if the reason matches those listed in (2)(a), (b), or (c), but must notify the appropriate AER field centre in advance through the designated information submission system as soon as the licensee recognizes that the time limit will be exceeded. The licensee must include reasons for the extension and the duration of the flaring, incinerating, and venting.

   a) If an audited licensee fails to justify the need to exceed the time limitation to the AER field centre's satisfaction, the licensee may be subject to a regulatory response.

5) If more time for well test flaring, incineration, or venting is needed for reasons other than those listed above, the AER must be contacted for approval to continue as soon as possible, and no later than the end of the specified period.

6) If a temporary flaring/incineration permit has been issued, the volume allowed in the permit will take precedence over the time limit described in (1) above.

7) When well test information indicates that cleanup is complete and the well flow is stabilized and all other AER requirements (e.g., AER *Directive 040*) are met, flaring/incineration/venting must be discontinued, even if the time limit or the flaring/incineration permit volume has not been reached. This requirement does not apply to bitumen or wet coalbed methane wells. Timing requirements for bitumen are in section 2.4(2). Timing requirements for wet coalbed methane wells are in (8) below.

8) For wet coalbed methane wells producing more than 1 m^3 of water per operating day, flaring/incinerating or venting must cease (gas must be conserved) within six months of gas production for an individual well exceeding a cumulative total of 100 10^3 m^3 for any

consecutive three-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued wherever possible.

a) Licensees must notify the AER Authorizations Branch as soon as the cumulative total gas production exceeds 100 10^3 m^3 for any consecutive three-month period at a wet coalbed methane well that is flaring, incinerating, or venting.

b) For wet coalbed methane wells that do not trigger the requirement above (i.e., 100 10^3 m^3 in 3 months), flaring, incineration, and venting are limited to the lesser of

   i) a total period of 18 months, including the time to tie in the well, or

   ii) a total cumulative volume of 400 10^3 m^3 for tier 2 (development) wells or 600 10^3 m^3 for tier 1 (other) wells per zone tested (see section 3.3.1[2]). Wells already tied in are treated as tier 3 and allowed a maximum cumulative flare, incineration, and vent volume of 200 10^3 m^3.

c) If additional flaring/incineration or venting durations or volumes are needed to test a coalbed methane well producing more than 1 m^3 of water per operating day, the licensee must make a written request to the AER Authorizations Branch as early as possible and in no case later than the end of the 18-month or volume allowance flare/incineration or vent period. Any request must include the reasons for the extension. Extensions may be granted to allow for additional flaring/ incineration/vent duration or volume for reservoir evaluations or if other special circumstances warrant.

3.3 Temporary Flaring/Incineration Permits

Figure 4 depicts the temporary flaring/incineration permit process.

The AER may suspend well flaring or incineration for noncompliance with conditions of the permit. The licensee must comply with the conditions of the temporary flaring permit.

3.3.1 Conditions That Require a Temporary Flaring/Incineration Permit

Note that an exemption for flaring small volumes of sour gas is found in section 3.3.2(2).

1) Licensees must obtain a permit to flare or incinerate sour gas containing more than 50 mol/kmol H_2S (5 per cent) or sour gas from any well classified as a critical sour well.

   a) If operations result in H_2S concentrations that are higher than concentrations at the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined in order to establish whether a permit is required. This composition must also be used in any required dispersion modelling.

   b) If supplemental fuel gas is used, the resulting composition must be used for dispersion modelling. However, the gas composition from the source is still used as the basis for determining whether a permit is required.

2) Licensees must obtain a permit for temporary flaring or incineration of natural gas if gas well test volumes exceed the volume allowance threshold. This is based on the volume of gas flowed back from the well (and does not include fuel gas added, and volumes from vented nitrogen or carbon dioxide used in fracturing fluid).

   a) The volume allowance threshold is defined in three tiers based on the volume of raw gas flowed back from the well (not including fuel gas added and carbon dioxide [CO_2] or nitrogen used for hydraulic fracturing). These volumes apply to gas well tests only:

      i) **Tier 1 ≤600 10^3 m^3**: applies to wells that have not been tied in and have a Lahee classification of new field wildcat (NFW), new pool wildcat (NPW), deeper pool test (DPT), or outpost (OUT).

      ii) **Tier 2 ≤400 10^3 m^3**: applies to wells that have not been tied in and have been assigned a Lahee classification (including development) not listed in the tier 1 allowance (excluding re-entry [REN] and experimental [EX] wells. See (b) and (c) below).

      iii) **Tier 3 ≤200 10^3 m^3**: applies to any well that has been tied in to facilities appropriately designed to handle production from the formation being tested (e.g., sweet versus sour service).

      All requested volumes must be justified and may be questioned by the AER.

   b) The volume allowance threshold for a re-entry well is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as re-entry.

   c) For wells with a Lahee classification of experimental, the volume allowance threshold is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as experimental or that normally would have applied to the well had it not been classified as experimental.

   d) An incremental volume of 200 10^3 m^3 may be added to the volume allowance threshold defined above for each additional zone being tested during continuous operations on a well (with continuous operations meaning that servicing equipment and personnel are not demobilized between tests on each zone), subject to the following limitations:

      i) The volume flared from any zone during multiple-zone tests must not exceed the volume allowance threshold for a single zone unless a larger volume is specifically approved by the AER Authorizations Branch.

      ii) The incremental allowance does not apply to single tests over multiple commingled zones. Each zone to be tested must be identified and fully accounted for in the related flare permit request.

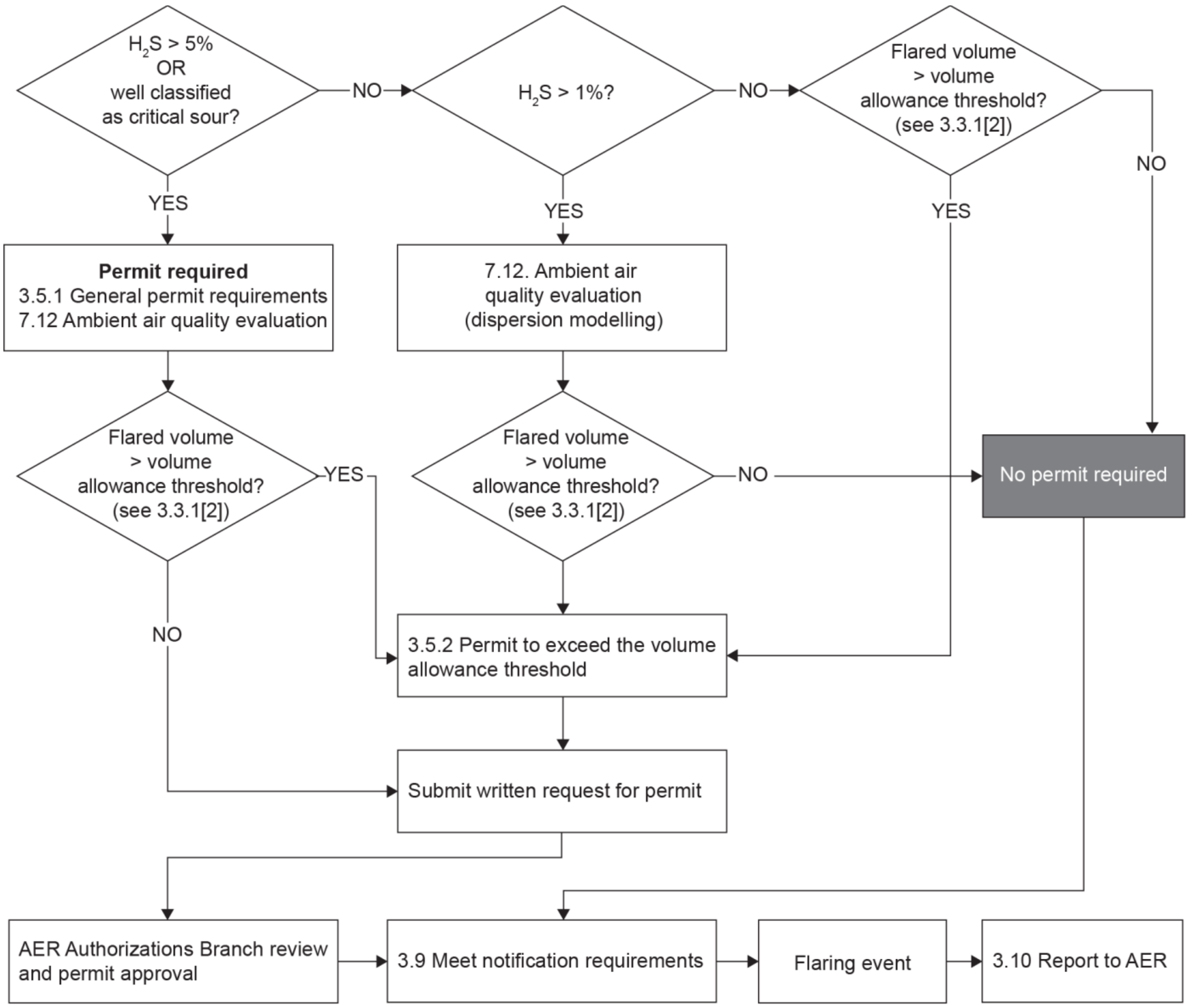

Figure 4. Temporary flaring/incineration permit process

3.3.2 Conditions That Do Not Require a Temporary Flaring/Incineration Permit

1) A permit is not required if the gas contains 50 mol/kmol H_2S (5 per cent) or less and the total volume (for gas well tests) is less than the volume allowance threshold (see section above). However, licensees must meet the requirements in section 3 and section 7, as well as the notification requirements in section 3.8.

   a) Licensees must evaluate compliance with the one-hour *AAAQO* for SO_2 if the gas contains more than 10 mol/kmol H_2S (1 per cent). Related dispersion modelling results must be provided to the AER Authorizations Branch upon request.

2) Flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H_2S (5 per cent) are exempt from AER permit requirements provided that the following conditions are met:

   a) Maximum sulphur emission rates do not exceed 1.0 tonne/day over the duration of the event.

b) Total flared or incinerated volume do not exceed 50 10^3 m^3 over the duration of the event.

c) Equipment is designed to ensure compliance with the one-hour *AAAQO* for SO_2 or operating procedures are in place to ensure compliance with the *AAAQO*. Related dispersion modelling evaluations and design information are documented and available to the AER Authorizations Branch upon request.

d) Rates and volumes are measured and reported as defined in section 10.

e) Written notification is provided to the AER Authorizations Branch. Notification includes total expected gas volumes and sulphur emissions. If applicable, notification provides an explanation of any air quality management plans needed to ensure compliance with the *AAAQO*.

3) The AER does not require temporary permits for the use of permanent flares or incinerators installed in AER-licensed facilities, including batteries, compressor stations, and gas plants provided that licensees can show, on request from the AER Authorizations Branch or field centre staff, that

a) the flaring or incineration volumes, rates, and gas composition are within the limits of the facility licence;

b) the flares or incinerators are designed to operate safely under the intended conditions in compliance with the *AAAQO*; and

c) the total volumes are less than the volume allowance threshold.

4) Similarly, the AER does not require temporary permits for unplanned nonroutine events such as emergencies. Licensees must ensure that temporary nonroutine systems are adequately designed to operate safely under anticipated emergency and upset conditions and meet the requirements in section 7.

a) For planned nonroutine events, including maintenance blowdowns, pipeline depressurizing, and turnarounds, licensees must obtain a temporary permit if required by section 3.3.1, unless exempted in (2) or (3) above.

5) The AER does not require temporary permits for flaring at oil and bitumen batteries. The operator must meet conservation requirements described in section 2.

3.4 Flaring and Incineration Permits for Underbalanced Drilling

Permit requirements (section 3.3) and notification requirements (section 3.8) for temporary flaring and incineration also apply to underbalanced drilling.

For more detail on underbalanced drilling requirements, see appendix 5.

3.5 Permit Requirements for Temporary Flares and Incinerators

Figure 4 summarizes the temporary permit process.

3.5.1 General Permit Requirements

1) Requests for temporary permits must be submitted to the AER Authorizations Branch via email (Directive060Inbox@aer.ca) and must include complete information on the proposed activity, as requested in the AERflare.xls and AERincin.xls spreadsheets (available on the AER website) and summarized as follows:

    a) a cover letter requesting a permit and informing the AER Authorizations Branch of any public objections to or concerns about the proposed flaring/incineration

    b) information about the site on which flaring/incineration will occur, including location, Lahee classification, and related National Topographical System 1:50 000 scale maps

    c) an evaluation of the most feasible option for in-line testing

    d) information on planned flaring/incineration, including reasons (e.g., well testing, completions, pipeline depressurizing), H_2S content, flow rates, total volumes, and type of combustion device to be used (i.e., flare or incinerator)

    e) information on the licensee's assessment of effects on ambient air quality, including results of dispersion modelling for SO_2

    f) in situations with potential to exceed the risk-based criteria (see section 7.12.4) for SO_2, information on the licensee's proposed air quality management plan to prevent exceedances

2) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee. Permit requests are processed in the order received, and resubmissions will be treated as new permit requests.

3) Temporary permit requests can be submitted electronically by the licensee. A permit will be in the name of the licensee.

3.5.2 Requests to Exceed the Volume Allowance Threshold

Information requirements apply to all requests to exceed the volume allowance threshold. However, any volume of gas flared or incinerated must be defensible.

1) Licensees must provide specific engineering, economic, and operational information to justify flaring or incinerating gas volumes in excess of the volume allowance threshold.

2) All requests for volumes greater than the volume allowance threshold regardless of H_2S content must be submitted to the AER Authorizations Branch (email Directive060Inbox@aer.ca) and must include the following, in addition to information in section 3.5.1 (note that 1[e] and [f] of that section do not apply to sweet gas wells).

a) Requests relating to tests to determine if enough gas supply exists to justify related investments must include information on the scope of development required to produce the well and necessary threshold reserves. (See appendix 5).

b) Requests relating to tests to determine the relationship between absolute open flow (AOF) and deliverability of the well must include justification of the volume being requested as it pertains to obtaining an accurate deliverability relationship, in accordance with AER *Directive 040*.

c) Requests relating to tests to establish the stabilized flow rate of the well must include justification of the flare volume request as it pertains to obtaining a stabilized flow rate, including identification of any analogous wells being used for comparison purposes.

3) Should the information described above not be available or applicable, licensees must include discussion on why it is not included with the exceedance request.

4) For underbalanced drilling, follow the guidelines in appendix 5.

3.5.3 Blanket Flaring/Incineration Permits

Sour oil and gas well operations such as well servicing may result in flaring of relatively small volumes of gas at several sites in a local area. To simplify temporary permit request requirements, the AER Authorizations Branch may issue a single "blanket" permit to cover several flaring events at different sites in an area if so requested by the licensee. Blanket permit request requirements and limitations are as follows:

1) Blanket permits are issued on a fixed-term basis for periods not to exceed one calendar year. Licensees must complete and submit a new flare permit request to renew blanket permits for additional periods of time.

2) Blanket permits are limited to specific stack heights, locations, rates, maximum volumes per event, maximum H_2S concentrations, and maximum sulphur emissions per event as listed in the permit request.

3) All wells must be licensed before they can be considered for a blanket permit.

4) For every well being considered for a blanket permit, licensees must use the AERflare.xls or AERincin.xls spreadsheet (available on the AER website) to evaluate the temporary flaring or incineration parameters during the period in which flaring/incineration is planned.

a) The spreadsheets provide screening modelling. Refined modelling may be required and must meet the risk-based criteria.

b) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee.

5) A blanket permit will not be considered if

a) projected volumes are greater than 100 10^3 m^3 per site or flaring event;

b) total sulphur emissions will exceed 10 tonnes per event;

c) an air quality management plan is necessary for compliance with the risk-based criteria for SO_2; or

d) complex terrain modelling is required for specific locations.

Exceptions may be made only after consultation with the AER Authorizations Branch.

6) A list of wells and their bottomhole and surface locations and licence numbers must be submitted to the AER Authorizations Branch before a blanket permit request will be considered.

7) A sour gas flaring/incineration data summary report (see appendix 6) for each well must be completed and submitted to the AER Authorizations Branch within 30 days of the end of each calendar quarter-year.

   If no flaring or incineration was done over the previous calendar quarter-year, a sour gas flaring/incineration data summary report on the lack of flaring or incineration must be submitted.

8) Licensees must comply with public and AER field centre notification requirements for each flare event covered by the blanket permit, as described in section 3.8.

3.5.4 AER Review of Permit Requests

Requested volumes, rates, or conditions may not be granted by the AER Authorizations Branch. Consideration will be given to total volumes, total sulphur emissions, local land uses, proximity of residences, and potential for exceedance of the *AAAQO* before a permit is granted. AER Authorizations Branch staff will consult with licensees in such situations.

1) Licensees must avoid temporary flaring or incineration in situations where existing infrastructure can be reasonably used for in-line disposition of the gas, especially in populated areas.

2) Licensees must limit the volumes for gas that they request, especially gas with high H_2S contents. Situations involving sulphur emissions of 50 tonnes or more are subject to closer scrutiny by the AER Authorizations Branch. The AER Authorizations Branch typically will not approve permits where total sulphur emissions exceed 300 tonnes.

3.6 Site-Specific Requirements Related to Well Flaring and Incineration

The following requirements apply to the use of temporary flares and incinerators.

1) Temporary flares and incinerators must comply with design and operation requirements defined in section 7.

a) Flares and incinerators must not be operated outside design operating ranges as specified by the designing or reviewing qualified technical professional who is a member of the Association as defined in the *Engineering and Geoscience Professions Act.*[9]

2) Licensees must determine the H_2S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as is practical after beginning operation if gas analysis has not been done within the preceding 12 months.

3) If the H_2S content in the gas is found to exceed 50 mol/kmol H_2S and no flaring or incineration permit has been issued by the AER Authorizations Branch, or if the H_2S content of the gas exceeds the maximum value listed in the related permit, operations must be suspended and the appropriate AER field centre notified. Operations must not resume until a permit or permit amendment is issued by the Authorizations Branch in response to a written request.

4) Both high- and low-pressure gas-liquid separation stages must be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.

5) Liquid storage must be designed to prevent the escape of sour gas to the environment. For more detail, see the most current edition of *Industry Recommended Practice [IRP] Volume 4: Well Testing and Fluid Handling* from the Canadian Petroleum Safety Council.

3.7 Temporary Facilities for In-Line Tests

To facilitate conservation, the licensee or operator may install a temporary compressor and pipeline connections. For temporary compressor installation, see *Directive 056*.

Section 3.7 of this directive does not apply to oil batteries. However, *Directive 056* application requirements apply to both temporary and permanent oil batteries.

1) Details on application requirements and exceptions for temporary well test facilities and pipeline connections are in *Directive 056*. In the case of a discrepancy between this directive and *Directive 056*, *Directive 056* application requirements apply.

2) Exceptions to AER applications requirements for temporary facilities, such as temporary connection to existing gathering systems, are intended to encourage conservation of gas associated with well testing. The provisions do not apply to testing situations in which gas will be flared.

3) Only one test period will be approved at each site. If there are multiple events, an application is required (see *Directive 056*).

4) For extended tests or multiple tests that require temporary facilities to operate for more than 21 days, the licensee or operator must complete an application (see *Directive 056*).

[9] *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

5) Proposals to install temporary compressors and other facilities for reasons other than testing new wells must comply with *Directive 056* application requirements.

6) Any licensee or operator intending to use temporary production, compression, and/or pipeline facilities must notify the appropriate AER field centre and obtain approval for a variance from *Directive 056* application requirements.

   a) The notification must include a description of the proposed equipment (including relevant capacities), driver type, and layout (e.g., give the compressor power rating and note whether the driver type is gas, diesel, or electric).

   b) A licensee or operator intending to install and use temporary pipelines for well testing must complete and submit to the appropriate AER field centre the Checklist for 21-Day Temporary Surface Pipelines for Well Testing Purposes.[10]

   c) AER field centre approvals for temporary facilities are valid for 21 days and include the dismantling and removal of temporary facilities (including pipelines) from the lease. Any exceptions, including allowances for downtime during testing, must be referred to the appropriate AER field centre for further review.

7) Temporary facilities, including pipelines, must comply with relevant AER requirements.

   a) Temporary facilities must meet noise control requirements defined in *Directive 038: Noise Control*.

   b) The licensee or operator must meet emergency response plan requirements for sour wells. The plan must incorporate provisions for the temporary equipment, as appropriate. See *Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry*.

8) Temporary sweetening processes, if used, must be of the zero-sulphur-emissions type. The licensee or operator must submit a facility application, as described in *Directive 056*, for temporary installation of regenerative sweetening processes with acid gas.

   a) All temporary or permanent regenerative sweetening facilities require an AEP sour gas processing plant approval.

9) Temporary pipelines and batteries must comply with *Directive 056* public consultation requirements.

3.8 Notification Requirements

Unless the licensee, operator, or approval holder reaches, with the people who require notification in accordance with this directive, an agreement that provides for an alternate means of notification, the licensee, operator, or approval holder must provide notice of flaring, venting,

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[10] Available on the *Directive 056* page of the AER website, www.aer.ca.

or incineration in accordance with this directive. The AER does not require the licensee, operator, or approval holder to obtain the consent of residents within the notification radius.

1) The licensee, operator, or approval holder must notify all residents and schools of flaring, incineration, and venting in accordance with table 2. The notification distances in table 2 are minimum requirements.

2) Notice must be given to the appropriate AER field centre via the designated information submission system of any planned flaring, incineration, or venting at least 24 hours in advance.

   a) Notice to the appropriate AER field centre must include a contact name and telephone number in case of complaints or emergencies.

Table 2. Temporary flaring, venting, and incineration notification requirements[1]

Type of operation (applies to sweet and sour streams)	Duration of event (hrs in 24-hr period)		Gas volume[2] (10^3 m^3 in a 24-hr period)	Notification[3,4]
Temporary (i.e., for well cleanup, testing, or maintenance)	<4	and	<30	No notification[5]
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains ≤10 mol/kmol H_2S	>4	or	>30	Residents, schools, 1.5 km radius; AER field centre
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains >10 mol/kmol H_2S	>4	or	>30	Residents, schools, 3 km radius; AER field centre
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	<4		--	No public notification;[5] Notify the AER if flaring >30 10^3 m^3
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	>4		--	Residents, schools, 0.5 km radius; AER field centre

1 See section 1.6 for information on the designated information submission system and how to notify the appropriate AER field centre via the system.

2 Notification requirements include duration and volume from flowback operations. These gases may be hydrocarbon or gases used in fracturing fluids (carbon dioxide or nitrogen) in any mixture. For reporting purposes, hydrocarbon volumes must be distinguished from fracture gas volumes (see section 3.9).

3 24 to 72 hours in advance of planned flaring, venting, or incineration operations, the licensee, operator, or approval holder must notify the appropriate AER field centre via the designated information submission system, all rural residents outside towns, villages, and urban centres and within the specified radius, and the chief administrative officer or equivalent of a town, village, or urban centre within the specified radius. Note that for incorporated centres and hamlets, it is sufficient to contact only the appropriate administrator. Advance notification of more than 72 hours (but not longer than 90 days) must also offer the option for renotification 24 to 72 hours before the start of operations. After 90 days, renotification is mandatory.

4 The AER recommends additional “good neighbour” notification for short-duration events for residents and schools that have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility within the same notification radius as specified for events of more than four hours.

5 The AER recommends additional “good neighbour” notification for longer duration events (of more than four hours) for residents and schools that have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility.

3) Upon AER field centre request, the licensee, operator, or approval holder must provide a list of residents and schools notified within the specified notification radius, as well as a sample of the information provided to residents.

4) Unless the licensee, operator, or approval holder has reached an agreement with current residents or schools for an alternative method of notification, notification must be in writing (see appendix 9) and include the following basic information about the flaring, incineration, or venting:

   a) licensee, operator, or approval holder's name, contact persons, and telephone numbers

   b) the location of the flaring, incineration, or venting

   c) the duration of the event (start date and expected completion date)

   d) the expected event volume and rates

   e) information on the type of well (oil, gas, or coalbed methane) and, if applicable, information on the H_2S content of the flared or incinerated gas

   f) AER field centre contact telephone number

5) The licensee, operator, or approval holder may conduct a one-time notification program for multiple-well projects in an area unless the licensee, operator, or approval holder has reached an agreement with current residents or schools for an alternative method of notification. In addition to the information above, the related multiple-well project notification must provide

   a) the locations where flaring, incineration, or venting will occur,

   b) the period during which the project will be carried out, and

   c) the expected duration and volume of temporary flaring, venting, or incineration.

6) The licensee, operator, or approval holder may limit the number of repeat notifications to individual residents or schools if

   a) the resident or school requests that the number of notifications be reduced;

   b) the licensee, operator, or approval holder provides the resident or school with an outline of expected flaring and incineration activities in the area; and

   c) the licensee, operator, or approval holder has a written agreement to reduce notifications and obtains acceptance of the agreement in writing from the resident or school. A copy of this written agreement must be provided to the AER upon request.

7) The licensee, operator, or approval holder may conduct a single notification to each resident and school within the notification area and the appropriate AER field centre, rather than a separate notification for each flaring, venting, or incineration period throughout the program, if this is acceptable to the current residents. The method of notification must be discussed during the initial notification process.

8) The AER recommends that the licensee, operator, or approval holder consider placing signage on public roads surrounding the temporary flaring or incineration operations indicating the operation type and the contact phone number for inquiries.

3.8.1 Addressing Resident Concerns

Compliance with *Directive 060* ensures that licensees, operators, and approval holders have considered public safety and environmental impacts before flaring, incineration, and venting activities; however, additional concerns or complaints may be expressed by nearby residents or schools regarding impacts of the operational aspects of flaring or incineration (e.g., timing of flaring and associated traffic). The following ensure that concerns of nearby residents and schools are addressed:

1) The AER encourages the licensee, operator, or approval holder to work with nearby residents and schools prior to commencing proposed and existing flaring or incineration activities.
2) The licensee, operator, or approval holder must immediately disclose any unresolved concerns of nearby residents and schools about those activities to the appropriate AER field centre in order to discuss concerns or complaints related to those activities.
3) Residents and schools may subsequently contact the appropriate AER field centre to discuss concerns or complaints related to those activities.

The AER may work further with the licensee, operator, or approval holder to modify one or more operational aspects of the proposed or existing flaring or incineration activities to address the concerns of nearby resident and schools, but it will not suspend flaring or incineration activities in response to a concern or complaint unless there is clear evidence that the licensee, operator, or approval holder is not in compliance with *Directive 060*.

3.8.2 AER Flaring/Incinerating/Venting Notice Form

1) To comply with the requirements in section 3.8 above, the licensee, operator, or approval holder must complete the AER flaring/incineration/venting notice form in the designated information submission system and submit it electronically to the appropriate AER field centre.

3.9 Reporting Gas Well Test Data

1) Well test results and information required by flaring and incineration permits must be submitted in accordance with the requirements of *Directive 040*, the applicable permit, and section 10.
    a) All well test reports must be submitted within three months of completing the fieldwork. This information must include the volume of gas produced to flare, vent, or pipeline, as well as all gas analyses from samples gathered at the wellhead. Submissions must be in

a pressure ASCII standard (PAS) format and submitted via the well test data capture system in the designated information submission system. For questions on these submissions, email the well test help line at Welltest-Helpline@aer.ca.

2) For all well tests that require permits, a sour gas flaring/incineration data summary report must be submitted to the AER Authorizations Branch within three weeks of the completion of flaring or incineration (see section 10.1, appendix 6, and AERflare.xls or AERincin.xls spreadsheet).

3) All flaring, incineration, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including Petrinex (see *Directive 007: Volumetric and Infrastructure Requirements*).

   a) In order to be able to report to the AER, the licensee, operator, or approval holder must obtain a battery code. Any produced volumes, including those flared, incinerated, or vented, must be reported (see *Directive 007*).

   b) Fluid volumes and fuel consumption must be recorded and reported on the monthly production submissions (see section 10).

3.10 Zero Flaring Agreements

Flaring is allowed by the AER when done in accordance with *Directive 060*. However, parties may agree to zero flaring, as set out in a zero flaring agreement (see appendix 10). The agreement must be signed by both parties and filed by the applicant with the well application. Once filed, the zero flaring agreement becomes a condition of the well licence. Should the licensee, operator, or approval holder fail to adhere to this agreement, operations at the well may be suspended. This agreement, including the condition, expires when production begins.

Once the well or facility is licensed, if the licensee, operator, or approval holder needs to change this zero flaring agreement, it must file an application to change the agreement with the AER Authorizations Branch, with a copy to the co-signers.

1) An application to change a zero flaring agreement must include

   a) the reasons that the agreement needs to be changed,

   b) a copy of the original application and approval,

   c) a copy of the original and revised zero flaring agreement, and

   d) a summary of the consultation and notification that have been done, including confirmation of agreements reached with the parties affected by this agreement.

Until the AER decides on this application, flaring may only occur as set out in the zero flaring agreement. For oil wells, agreement not to flare during well testing means that the licensee, operator, or approval holder has agreed to initially conserve the gas. Later, if it becomes uneconomic to conserve the gas, the licensee, operator, or approval holder must follow the process in section 2.6(6) of this directive to discontinue conservation.

The licensee, operator, or approval holder must try to address the landowner or occupant concerns and may use the AER's alternative dispute resolution process if that becomes necessary before applying with the AER to change this zero flaring agreement.

4 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting

This section addresses gas battery, dehydrator, and compressor station flaring, incinerating, and venting and includes

- routine flaring and incineration, and
- nonroutine flaring, incineration, and venting for equipment depressurization for maintenance; process upsets; and emergency depressurizing for safety reasons.

4.1 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting Decision Tree

1) The licensee or operator must use the decision tree analysis shown in figure 5 to evaluate all new and existing gas battery, dehydrator, and compressor station flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressurizing.

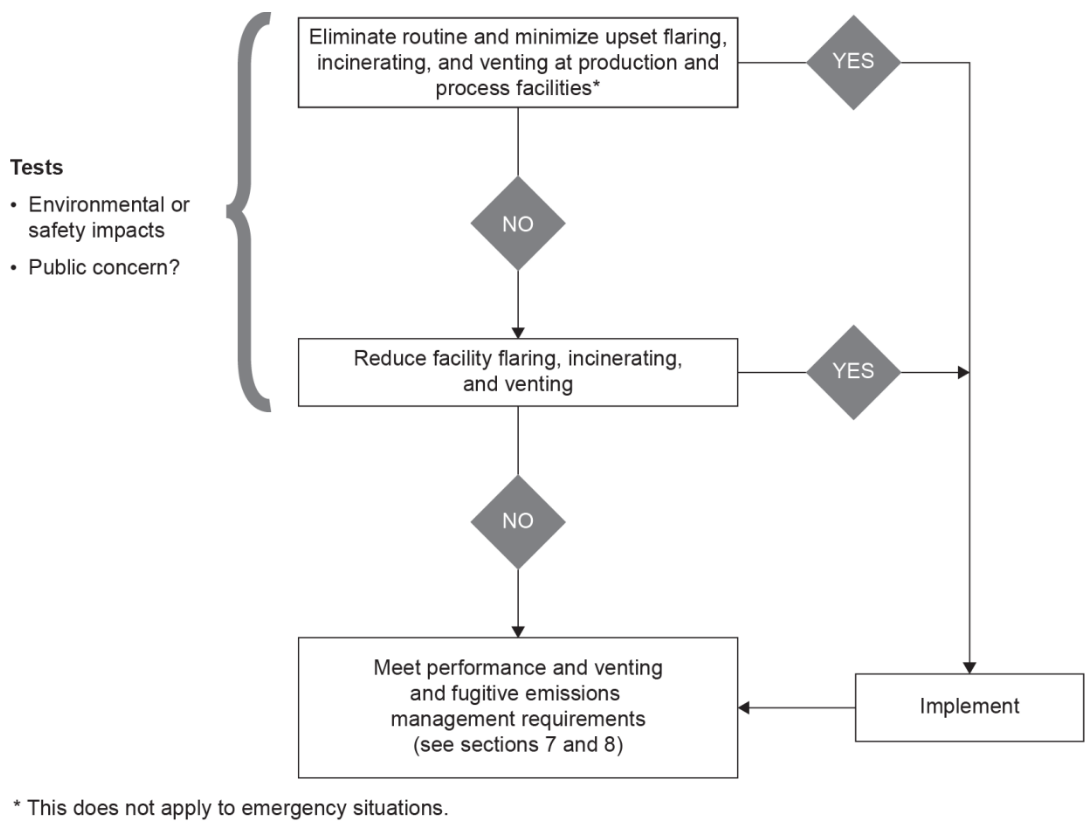


Figure 5. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

2) The licensee or operator must document alternatives that were considered in order to eliminate or reduce flaring, incineration, and venting, how they were evaluated, and the outcome of the evaluation.

3) New batteries proposing routine flaring, venting, or incineration must be evaluated before application as part of the facility design. All existing batteries with routine sources were required to have been evaluated by December 31, 2004.

4) The licensee or operator must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent (i.e., one event per month) maintenance or facility shutdowns.

   a) The licensee or operator must investigate and correct frequent nonroutine events at gas batteries.

   b) The licensee or operator must address concerns or objections of residents and schools related to nonroutine gas battery flaring.

5) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.

4.2 Notification

1) The licensee or operator must notify residents, schools, and the appropriate AER field centre of nonroutine flaring at gas batteries as follows:

   a) If gas battery flaring exceeds four hours in duration, the licensee or operator must notify residents and schools as described in section 3.8 and table 2.

   b) If a gas battery flaring event exceeds 30 10^3 m^3 and/or four hours in duration or is likely to cause concern for residents or schools, the appropriate AER field centre must be notified (see table 2). If *Directive 060* notification requirements differ from those of *IL 98-01: A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*, the licensee or operator must comply with the more stringent requirement.

2) The licensee or operator must give the AER field centre at least 24 hours' notice of planned gas battery outages and turnarounds that will result in flaring of more than 30 10^3 m^3 or for more than four hours duration. The licensee or operator must give residents and schools notification without delay or as soon as practical of unplanned gas battery outages that result in flaring of more than 30 10^3 m^3 or for more than four hours.

4.3 Reporting

1) All monthly flared and vented volumes must be reported separately on Petrinex in accordance with sections 8 and 10 and *Directive 007*. Incinerated volumes must be combined with and reported as flared volumes.

2) Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as flared.

3) Gas flared or vented at gas batteries must be reported at the flaring or venting location. For facilities that do not require a licence (such as small booster compressors), the flared and vented volumes must be reported at the nearest upstream reporting well, battery, or pipeline facility.

5 Gas Plant Flaring, Incinerating, and Venting

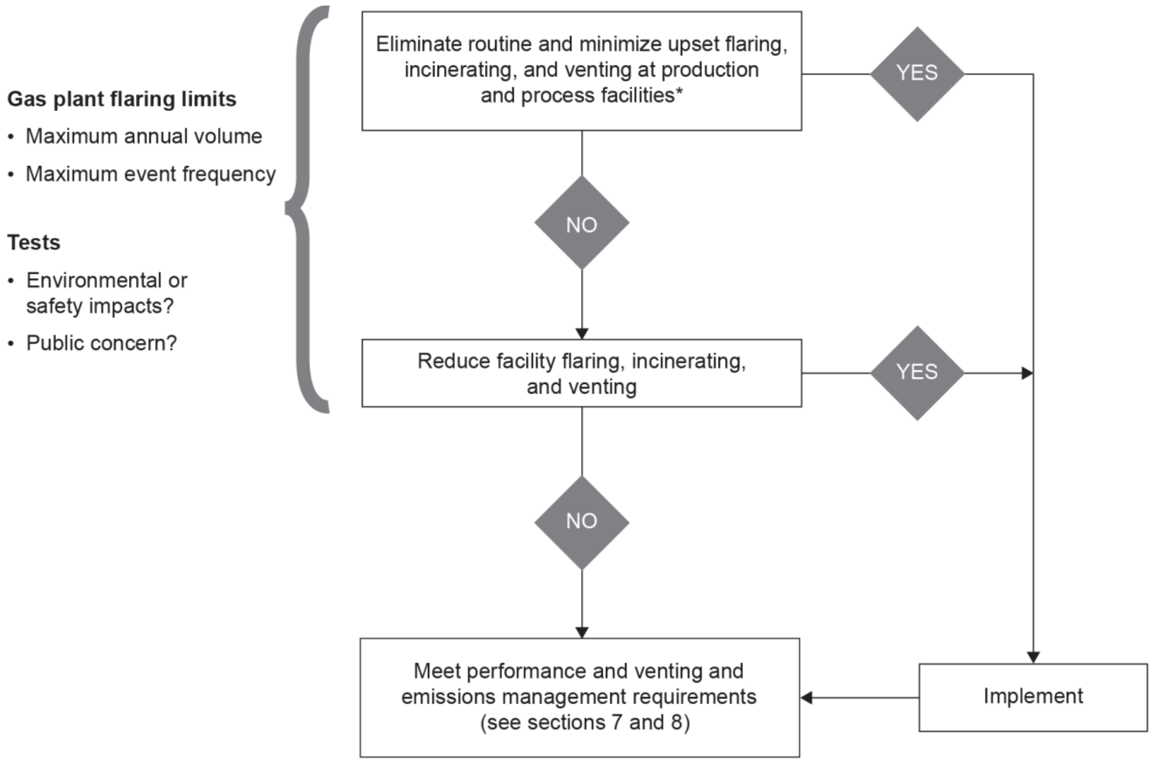
This section addresses disposal of gas from gas processing plants by flaring, incinerating, and venting. Sources of natural gas flaring, incineration, and venting at gas production facilities include

- routine flaring, incineration, and venting of low-pressure flash-gas and other gas streams, and
- nonroutine flaring, incineration, and venting for equipment depressurizing for maintenance process upsets, and emergency depressurizing for safety reasons.

5.1 Gas Plant Flaring, Incinerating, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 6 to evaluate all new and existing gas plant flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressurizing. Furthermore, these evaluations must be updated annually or when changes at the plant materially change plant operation.

1) Licensees must document alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.
2) Licensees must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent maintenance or facility reliability outage, as well as
    a) address concerns and objections of residents and schools notified in accordance with table 2 related to nonroutine flaring, and
    b) comply with the limitations on total flared, incinerated, and vented volumes and the number of repeat events defined in sections 5.2 and 5.3.
3) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.
    a) Gas streams directed to continuous gas plant flares must have a minimum heating value as defined in section 7.1.1.
    b) All existing plants were required to have performance evaluations completed by December 31, 2004.



* This does not apply to emergency situations.

Figure 6. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

5.2 Gas Plant Flaring/Incineration/Venting Volume Limits

The AER limits the total annual volume of gas disposed of by flaring, incineration, and venting at gas processing plants. Acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the following limits:

1) For gas plants processing more than $1.0\ 10^9$ m^3 per year (raw gas inlet volume), flaring, incineration, and venting must not exceed the greater of 0.2 per cent of raw gas receipts or $5.0\ 10^6$ m^3 per year.

2) For gas plants processing less than or equal to $1.0\ 10^9$ m^3 per year (raw gas inlet volume), flaring, incineration, and venting must not exceed 1.0 per cent of raw gas receipts in the first year of operation and must not exceed 0.5 per cent of raw gas receipts in any subsequent year with the following exception:

   a) For acid gas plants processing less than or equal to $0.1\ 10^9$ m^3 per year (raw gas inlet volume), flaring, incineration, and venting must not exceed 3.75 per cent of raw gas receipts in any year of operation.

3) If multiple flare stacks are available in gas production, gathering, and processing systems, licensees must use the flare stack that is the most efficient and capable of providing the best dispersion. In most cases this would be the gas plant flare stack.

a) Licensees can deduct solution gas flared at gas plants during plant shutdowns lasting more than seven days in calculating the annual flared volumes applicable to (1) and (2) above. These solution gas volumes must be documented and provided to the AER upon request.

4) Licensees must comply with the solution gas reduction limitations in section 2.11 during facility outages.

5) All nonassociated gas must be shut in during facility outages.

6) The AER recommends that solution gas processing take priority over the processing of nonassociated gas.

5.3 Frequent Nonroutine Flaring/Incineration/Venting Events

1) Licensees must investigate and correct causes of repeat nonroutine flaring, incineration, and venting.

2) Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period (6-in-6). Major flaring events are defined in table 3.

Table 3. Major flaring event definition

Approved plant inlet capacity	Major flaring event definition*
>500 10^3 m^3/d	100 10^3 m^3 or more
150–500 10^3 m^3/d	20 per cent of plant design daily inlet or more
<150 10^3 m^3/d	30 10^3 m^3 or more

* The definition of a flaring event includes situations where

- volumes greater than or equal to those specified in the table are flared in any single day; each day that specified flared volumes are exceeded is considered to be a separate, individual event; or
- volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (e.g., flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).

3) Licensees must log and monitor nonroutine flaring events, as required in section 10.1. Major flaring events must be flagged. The following applies if a sixth major flaring event occurs within any consecutive (rolling) six-month period:

a) Licensees must submit a written “exceedance” report to the appropriate AER field centre and copy this report to the AER Authorizations Branch within 30 days of the occurrence of the sixth flaring event.

i) The exceedance report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and on their possible causes.

ii) The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major nonroutine flaring does not recur.

b) Licensees must obtain AER field centre approval of the proposed plan referred to in 3(a)(ii) above.

i) If facility modifications are proposed in the plan and approvals are required by *Directive 056*, AER Authorizations approval must be obtained before implementing any such actions.

ii) Upon AER field centre approval of the plan, including facility modifications, licensees are expected to expedite schedules for implementing the plan.

c) After the plan implementation date, the AER may issue a regulatory response if another exceedance of the 6-in-6 criterion occurs within 24 months.

5.4 Notification

1) Licensees must notify residents, schools, and the appropriate AER field centre of nonroutine flaring at gas plants (see table 2).

a) The appropriate AER field centre must be notified if a nonroutine flaring event exceeds 30 10^3 m^3, exceeds four hours' duration, or is likely to cause public concern.

b) If more stringent notification requirements than required by this directive have been put in place through *IL 98-01*, licensees must comply with the more stringent requirements.

c) Licensees must provide the appropriate AER field centre with at least 24 hours' notice of a plant turnaround.

d) The appropriate AER field centre must be notified 24 to 72 hours before planned flaring and as soon as practical of unplanned flaring when notification is required.

5.5 Measurement and Reporting

Measurement and reporting requirements for gas plants include the following:

1) All monthly flared and vented volumes must be reported separately on Petrinex in accordance with section 10 and *Directive 007*.[11]

2) Flaring of sour gas must also be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report (see section 11 of *Directive 017*).

3) When metering is not required, engineering estimates must be used to report any flared gas not measured (see section 10).

4) Licensees must provide a documented system for metering and/or estimating flared and vented gas volumes (as defined in sections 8 and 10) upon AER Authorizations Branch

[11] This information is summarized annually in AER *ST13A: Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics*, and monthly in *ST13B: Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics*, and *ST13C: Alberta Gas Gathering System Activities—Monthly Statistics*.

request. All flare events both minor and major must be logged (in accordance with section 10.4) and provided upon request.

5) Gas that is flared or incinerated must be reported as flare gas.

6) Licensees must monitor and minimize gas used for flare header purges, flare pilots, and incinerator pilots.

    a) Licensees must be able to justify gas usage volumes.

    b) The AER may require evidence of this justification on the basis of case-specific audits and inspections.

6 Pipeline Flaring, Incinerating, and Venting

This section addresses disposal of gases from gas gathering and transmission lines by flaring, incineration, and venting. Sources of gas flaring, incineration, or venting include

- routine flaring, incineration, and venting of low-pressure flash-gas and other gas streams at pipeline system compressor and dehydration facilities, and
- nonroutine flaring, incineration, and venting for pipeline depressurizing for maintenance, process upsets, or emergency depressurizing for safety reasons.

6.1 Pipeline Systems Flaring, Incineration, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 7 to evaluate all new and existing pipeline systems, including compression station flares, incinerators, and vents, except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressurizing. These evaluations must be updated before any planned flaring, incinerating, or venting.

1) Licensees must document alternatives considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.
2) Licensees must assess opportunities to eliminate or reduce flaring, incineration, and venting of gas due to frequent maintenance or facility outage as follows:
    a) Investigate and correct repeat events at gas pipelines and related facilities (e.g., compressor stations).
    b) Address public complaints and concerns about pipeline facility flaring, incineration, or venting.
    c) Investigate and implement feasible measures to conserve gas from the depressurizing of pipeline systems.
3) Licensees of gas pipeline systems must ensure that flares, incinerators, and vents are designed and operated in compliance with sections 7 and 8, good engineering practices, and any other safety codes and regulations required by other agencies.
4) The sulphur recovery requirements of section 9 and *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* apply to any continuous flaring or incineration of sour gas at gas gathering facilities (e.g., compressor or dehydrator sites).

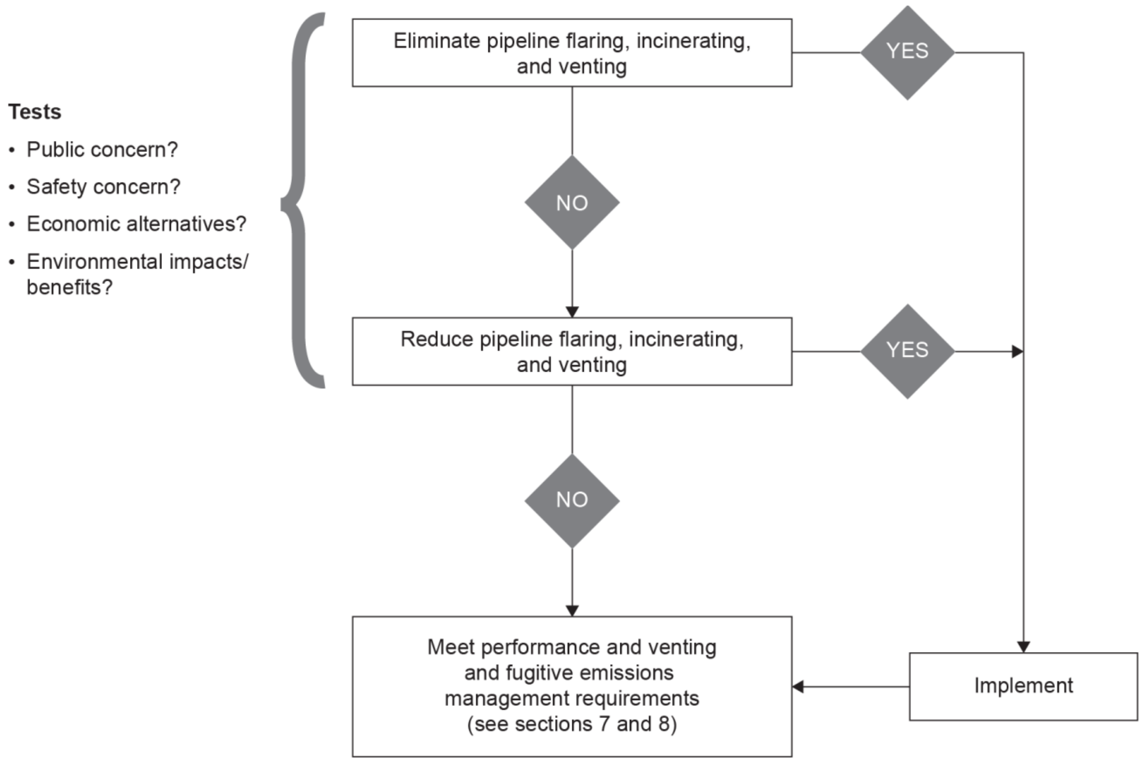


Figure 7. Pipeline flaring, incinerating, and venting decision tree (adapted from CASA)

6.2 Additional Requirements for Gas Gathering Systems

1) All monthly flared, incinerated, and vented volumes must be reported separately on Petrinex in accordance with section 10 and *Directive 007*. Incinerated volumes must be combined with, and reported as, flared volumes.

2) Gas containing more than 5 parts per million (ppm) H_2S must not be released from a pipeline without the approval of the AER unless the gas is burned such that it meets the requirements in section 7.

   - Flaring or incineration of gas must meet the requirements in section 7.
   - Venting of gas must meet the requirements in section 8.

3) Licensees must get an AER temporary flaring/incineration permit in order to use temporary flares or incinerators for the disposal of sour gas containing more than 50 mol/kmol (5 per cent) H_2S, as described in section 3.3.

   a) Permits are not required for disposal of small amounts of sour gas if the requirements defined in section 3.3.2 are met.

   b) Permit request requirements (section 3.5) apply to temporary flares and incinerators used for sour gas pipeline depressurizing, except in emergencies.

4) Notification requirements described in table 2 apply.

6.3 Natural Gas Transmission Systems

This directive applies to flaring, incineration, and venting in conjunction with natural gas transmission systems, subject to the following provisions:

1) Licensees of sweet natural gas transmission pipelines must minimize venting, flaring, and incineration volumes.

   a) The economic evaluation in section 2.9 does not apply to evaluating conservation of gas from nonroutine pipeline depressurizing for maintenance.

   b) When evaluating conservation of gas from planned nonroutine pipeline depressurizing, licensees must consider the value of gas, the costs of conserving the gas, and the economic effects of extending outages on downstream customers and upstream producers.

2) Flaring or incineration of gas from sweet natural gas transmission pipeline depressurizing may not be practical when impacts on system customers and producers are considered. In such situations, the appropriate AER field centre may allow the venting of gas to reduce the duration of system outages and related impacts.

6.4 Notification

1) Licensees must notify residents, schools, and the appropriate AER field centre of nonroutine flaring, incineration, or venting at licensed gas pipeline facilities as follows:

   a) If pipeline facility flaring, incineration, or venting exceeds four hours in duration or $30\ 10^3\ m^3$, licensees must notify as specified in section 3.8 and table 2.

   b) In areas where more stringent notification requirements than those defined in table 2 are required by *IL 98-01* or through other regulatory requirements, licensees must comply with the more stringent requirements.

2) Licensees must provide the appropriate AER field centre with at least 24 hours' notice of planned pipeline facility outages that will result in flaring, incineration, or venting.

3) When nonroutine pipeline flaring, incineration, or venting is planned, licensees of sweet natural gas transmission pipelines must notify the appropriate AER field centre and discuss the measures taken to minimize emissions.

4) Each purchaser or transporter of sweet natural gas must report the particulars of the disposition and delivery of its gas to the AER monthly (see section 12.051 of the *Oil and Gas Conservation Rules* [*OGCR*]).

   a) Flared and vented volumes of sweet natural gas must be reported separately. Incinerated volumes must be combined with, and reported as, flared volumes.

7 Performance Requirements

These requirements apply to flares and incinerators in all upstream oil and gas industry systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. Flare and incinerator systems include associated separation equipment, piping, and controls.

For the purposes of this directive, the terms flare and incinerator are used interchangeably except as specifically noted in sections 7.1, 7.4, and 7.8. In these sections, some requirements are specific to the type of equipment used, and this is specified in those requirements.

All requirements in *Directive 060* that apply to incinerators apply to enclosed combustors (a type of incinerator) unless otherwise stated. To be considered an enclosed combustor, an incinerator must meet the design and operation requirements in section 7.1.3. Section 7.8 sets out reduced equipment spacing requirements specific to enclosed combustors.

Although some design or operating specifications are provided, this directive is not a substitute for comprehensive engineering design codes and guidelines. It identifies minimum AER regulatory requirements but is not intended as a comprehensive design manual.

1) The licensee, operator, or approval holder must ensure that a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*[12] is responsible for the design or review of flare and incinerator systems, including separation, related piping, and controls, and for the specification of safe operating procedures.
    a) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.
2) The licensee, operator, or approval holder must ensure that operating procedures that define the operational limits of flare or incinerator systems are documented and implemented and that these procedures meet the design requirements.
    a) Operating limits and procedures must be provided to the AER immediately upon request.
    b) Flare and incinerator systems must be operated within the operational ranges and types of service specified by the designing or reviewing engineer, technician, or technologist. If this equipment is used for emergency shutdowns, this must be considered in the design.
3) If using, in a field service, a flare or incinerator that has not previously been field tested, the licensee, operator, or approval holder must be able to provide actual monitoring data to show that performance specifications will be met.

[12] *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

a) Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted, or unless the facility is capable of being shut in if problems arise.

4) *ANSI/API Standard 521: Pressure-Relieving and Depressuring Systems*, as well as applicable fire safety codes, electrical codes, CSA standards, and mechanical engineering standards, are all necessary references for the design of gas combustion systems.

5) The licensee, operator, or approval holder must comply with Alberta safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures (see *Pressure Equipment Safety Regulation*).

6) The AER recommends that all licensees, operators, and approval holders use best engineering practices, as well as appropriate engineering codes and standards, in the design and operation of flare systems.

7.1 Conversion Efficiency

Definitions and calculations for carbon conversion efficiency, sulphur conversion efficiency, and combustion efficiency are in appendix 2.

1) Flares and incinerators and other gas combustion systems, including those using sour gas as a fuel for production or process equipment, must be designed, maintained, and operated so that emissions do not

   a) result in off-lease H_2S odours, or

   b) exceed the *AAAQO*.

2) The licensee, operator, or approval holder must modify or replace existing flares or incinerators if operations result in off-lease odours, odour complaints, or visible emissions (e.g., black smoke).

7.1.1 Heating Value and Exit Velocity for Flares

If a flare is also subject to both an AER and an AEP approval, the more stringent requirement on minimum heating value will apply.

1) The combined net or lower heating value of gas, including makeup gas, directed to a flare must not be less than 20 megajoules per cubic metre (MJ/m^3), except as noted below:

   a) If existing stacks have an established history of stable operation and compliance with the *AAAQO* (the licensee, operator, or approval holder is expected to support claims that existing stacks have operated satisfactorily over time), the licensee, operator, or approval holder is allowed to maintain the current heating value provided it is not less than 12 MJ/m^3.

i) If flare stacks have a history of flame failure, odour complaints, or exceedances of the *AAAQO*, the licensee, operator, or approval holder must operate with a combined flare gas heating value of not less than 20 MJ/m^3.

b) The combined net or lower heating value of acid gas plus makeup gas directed to existing or new flares must not be less than 12 MJ/m^3 under any circumstance.

c) Sour gas plant emergency systems must be configured to ensure that the flared gas heating value is not less than 12 MJ/m^3 and that the *AAAQO* are met.

i) The AER recommends that 20 MJ/m^3 heating value be maintained for nonroutine flaring but recognizes that short-duration emergency flaring with a gas heating value of less than 20 MJ/m^3 may occasionally occur.

2) If makeup gas is required, it must be specified for flare stacks by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.[13]

a) Equipment controls must be installed, and operating procedures must be documented to ensure minimum makeup gas during routine and nonroutine operating conditions.

b) Facilities must be operated in compliance with specified requirements for minimum makeup gas.

3) The flare tip diameter must be properly sized for the anticipated flaring rates. The AERflare.xls spreadsheet provides a range of recommended values.

a) The AER recommends that stacks be designed to avoid downwash due to low exit velocities and excessive noise due to high exit velocities.

4) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.

5) Operating limits and procedures must be provided to the AER immediately upon request.

7.1.2 Minimum Residence Time and Exit Temperature for Incinerators

If an incinerator is subject to an *EPEA* approval, any requirements regarding minimum residence time or exit temperature in that approval will take precedence over these requirements. The requirements below do not apply to sour gas plants subject to AEP approvals.

1) Incinerators must provide a minimum residence time[14] of 0.5 seconds at maximum flow rate or more as required for complete combustion of heavier gases.

a) Incinerators must be operated without exposed flame.

[13] *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

[14] Residence time is calculated between the top of the final burner and the stack exit.

b) If the gas contains less than 10 mol/kmol (1 per cent) H_2S and the unsupplemented heating value of the gas is 20 MJ/m^3 or more, no minimum residence time is required.

2) Incinerators must operate with a minimum exit temperature[15] of 600°C.

a) For combustion of gases with less than 10 mol/kmol (1 per cent) H_2S and an unsupplemented heating value of 20 MJ/m^3 or more, no minimum exit temperature or temperature monitoring is required.

b) For combustion of gases with more than 50 mol/kmol (5 per cent) H_2S, the facility must be designed to automatically shut down if the exit temperature of the incinerator drops below either 600°C or the required temperature to meet the *AAAQO*, whichever is higher.

i) The incinerator must also be equipped with process temperature control and recording.

ii) All violations, together with measures taken to prevent recurrence, must be immediately reported by the licensee, operator, or approval holder to the appropriate AER field centre.

3) Any operator proposing to use combustion technology that does not meet the above requirements (minimum exit temperature and minimum residence time) must submit third-party-verified conversion efficiency test results to the AER Authorizations Branch for approval unless the facility is subject to an *EPEA* approval.

a) Test programs and submissions must be provided by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*[16] and must include

i) inlet gas parameters, including flow rates and composition;

ii) stack gas exit parameters, including temperature and composition;

iii) material and energy balance calculations;

iv) a mass-weighted conversion efficiency value representative of the exit conditions (see section 7.1.2[6] below);

v) discussion of the variation of measured and calculated results, depending on sampling location across the stack; and

vi) discussion of extending test results to other inlet conditions, including discussion of inlet limitations for H_2S concentration and inlet gas flow rate.

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15 Exit temperature must be measured within one stack diameter of the exit. A shielded thermocouple must be used if the burner flame is visible to the temperature monitor. For further information, consult the *Alberta Stack Sampling Code* or contact Alberta Environment and Parks.

16 *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

b) All testing must meet the *Alberta Stack Sampling Code*.[17]

c) Temperature monitoring and reporting requirements would still apply.

4) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.

5) Operating limits and procedures must be provided to the AER immediately upon request.

6) Any licensee, operator, or approval holder using incinerators must be able to provide details about the conversion efficiency of the equipment. Any of the following are considered to be acceptable evidence of compliance with this requirement:

a) the design at the maximum specified capacity meets the residence time, temperature, and conversion efficiency requirements (see [6][b] below), as calculated using the AERincin.xls spreadsheet

b) the conversion efficiency for incinerators is 99 per cent or more, based on one of the following:

i) the manufacturer's third-party-verified conversion efficiency test results, provided that the tests were conducted under conditions representative of the facility design

ii) actual field measurements of conversion efficiency from the operating facilities following start-up (see also section 7[3]) .

c) If conversion efficiency is less than 99 per cent, the incinerator will be considered to operate as a flare and must meet all requirements for flares, including stack height.

7.1.3 Design and Operating Parameters for Enclosed Combustors

1) Enclosed combustors must be designed and operated as follows:

a) Combustion process must be totally enclosed, except for the combustion air intake and the exhaust discharge.

b) There must be no visible flame.

c) All surfaces exposed to the atmosphere must

i) operate below the temperature that would ignite a flammable substance present in the surrounding area, or

ii) be shielded or blanketed in such a way to prevent a flammable substance present in the surrounding area from contacting the surface.

[17] Copies of the *Alberta Stack Sampling Code* are available at cost from the Queen's Printer.

d) Exhaust gases must be below auto-ignition temperature of a flammable substance present in the surrounding area.

e) All intakes must be equipped with a flame arresting device.

7.2 Smoke Emissions

1) Smoke emissions from a well, battery, or gas plant must be controlled in accordance with sections 7.040(1) and 9.050(6)(d) of the *OGCR*, except under emergency circumstances that involve equipment failure or as otherwise approved by the AER Authorizations Branch.

   a) Routine gas combustion must not result in continuous or repeat black smoke emissions.

   b) Black smoke from nonroutine or emergency flaring must not exceed an average of 40 per cent opacity over six consecutive minutes or as defined, after the issue of this directive, in Alberta's *Environmental Protection and Enhancement Act Substance Release Regulation.*[18]

2) Any smoke emissions that may result in public concern must immediately be reported to the appropriate AER field centre.

7.3 Ignition

1) Acid gas and sour gas flares and incinerators must have reliable systems that ensure continuous ignition of any gas that may discharge to the device.

   a) At all facilities (excluding gas plants and batteries regulated as crude bitumen batteries) where the gas contains more than 10 mol/kmol H_2S, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., sour water or condensate tank flash-gas) and intermittent (e.g., emergency depressurizing) sources.

   b) At crude bitumen batteries where the H_2S release rate is greater than 0.04 m^3/hr, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., storage tank flash-gas) and intermittent (e.g., truck loading operations) sources.

   c) At gas plants where gas contains more than 10 ppm H_2S, pilots and automatic ignition must be installed on flares and incinerators.

   d) If repeat failures have occurred or off-lease odours or other impacts have resulted from failure to ensure ignition of sour gas, regardless of H_2S content, the AER may require installation of

      i) pilots and automatic ignition, and/or

      ii) flame failure detection and alarms.

[18] *Substance Release Regulation*, AR 124/93.

2) Manual flare and incinerator ignition subject to good fire safety practices will be accepted for nonroutine purposes where

   a) no continuous gas flow exists, and

   b) no automatic relieving systems are connected to the stack.

7.3.1 Requests to Extinguish Sour Flare Pilots at All Batteries

Continuous pilots may be necessary where gas is flared or incinerated on a constant or routine basis (see section 7.3) or where sour gas can potentially be released from pressure safety valves (PSVs) or emergency shutdown valves (ESDVs). In situations where gas is not continuously or routinely flared, where ESDVs are not configured to depressurize facilities to flare, and where maximum foreseeable operating pressures are well below PSV release pressures, the potential exists to safely conserve natural gas by extinguishing the flare pilots.

When considering a request to extinguish flare or incinerator pilots, the AER field centre takes into account both local conditions and the operating history of the facility.

1) The licensee, operator, or approval holder must get approval from the appropriate AER field centre to extinguish flare pilots at sour gas batteries.

2) The issuing of an approval is only considered if

   a) the maximum design operating pressure of production piping and pressure vessel systems is greater than 105 per cent of the maximum stabilized static wellhead pressure of all wells connected to the battery;

   b) there will be no continuous or routinely flared or incinerated gas streams;

   c) the facility is connected to sweet or level-1 or level-2 sour wells;

   d) no active injection or cycling schemes are taking place in or planned for any pools with wells connected to the facility;

   e) the facility connections to the flare are isolated with rupture disks upstream of PSVs. This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association; and

   f) all manual depressurizing valves connected to the flare system contain double block valves.

3) Requirements for extinguishing flare or incinerator pilots are in appendix 11.

4) If the licensee, operator, or approval holder proposes to connect additional wells to an existing approval, they must first supply updated information and get approval from the appropriate AER field centre.

7.4 Stack Design

Flares and incinerators must meet or exceed the following stack design requirements:

1) Flare and incinerator stacks must be designed so that the total radiant heat intensity at ground level will not exceed 4.73 kilowatts per square metre (kW/m^2).

    a) Ground-level radiant heat determinations for flares must be based on calculation procedures outlined in the AERflare.xls spreadsheet, *ANSI/API Standard 521* section 6.4.2.3, or *GPSA Engineering Data Book* (13th edition), section 5. Incinerators must be operated without exposed flame.

    b) Exceptions to the requirement in section 7.4(1) will be considered on request to the AER Authorizations Branch, provided an equivalent level of safety can be ensured.

        i) In such cases, the licensee, operator, or approval holder must restrict access to the area where the radiant heat intensity guideline could be exceeded and must ensure that this area is free of combustible materials and vegetation. Access restrictions must include appropriate warning signs, and the area must be clearly marked.

        ii) Appropriate procedures (e.g., safe-work permit system) must be in place when it is necessary to work within the area where the radiant heat intensity guideline could be exceeded.

2) Flares and incinerators located within a distance of 5 times the height of any neighbouring buildings must have a height of at least 2.5 times the height of the highest building, tank, or enclosed structure on the lease site.

    - The foregoing does not apply to enclosed combustors or devices for destruction of trace vent gases, such as those emitted from gas dehydrators.

3) Flare stacks for acid or sour gas containing more than 10 mol/kmol H_2S must have a height of at least 12 m above ground level. At crude bitumen batteries where the H_2S release rate is greater than 0.04 m^3/hr, the minimum height above ground level for the flare stack is 12 m, or such greater height as may be required to ensure that the *AAAQO* are not exceeded. Existing crude bitumen batteries must meet the minimum height requirement by December 31, 2015.

4) Flares and incinerators must be high enough to provide adequate plume dispersion to comply with the *AAAQO* for SO_2 (see section 7.12).

    a) Proper stack heights must be used in order to minimize gas consumption. If the use of supplemental makeup gas is proposed, all other options must be investigated first. Make up gas use and amounts must be justified.

5) Interconnecting lines to the flare or incinerator must be secured to prevent whipping or flailing.

7.5 Sour and Acid Gas Flaring/Incineration Procedures

A licensee, operator, or approval holder must meet the requirements in this section or those in table 1, whichever is more stringent and results in more gas being shut in.

Devices for combustion of sour or acid gas must be designed and evaluated to ensure compliance with the *AAAQO* for SO_2. Evaluations must use methodologies acceptable to the AER Authorizations Branch and AEP. One of the methods described in section 7.12 or AEP's *Non-Routine Flaring Modelling Guidance* must be used.

1) A cumulative emissions assessment must be conducted if a flaring event is routine and if modelling results of the individual source exceed one-third of the *AAAQO* for SO_2 (see section 7.12).
2) It is not necessary to do a cumulative emissions assessment if the routine flaring is reasonably expected to be of short duration (less than four hours). Cumulative assessment requirements are intended to address the effects of multiple or continuous SO_2 sources in a given area (see section 7.12.3). Even if a cumulative emissions assessment is not required, modelling may still be required, as described in section 7.12.
   a) Operating procedures must be put into place to limit the release duration if the routine stack design is based on the above exception.
3) If operating procedures and controls are used to limit the magnitude or the duration of the event, they must be documented and the facility must be operated in accordance with these procedures.
   a) Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (i.e., are semi-attended) to ensure compliance with this requirement.
   b) Staff responsible for operations must be aware of the current operating procedures and must be trained at following them.
4) Operating procedures and related dispersion evaluations must be provided to the AER upon request.

7.6 Liquid Separation

Entrained liquids in a flare or incinerator stream may reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons, and products of incomplete combustion. Proper gas-liquid separation facilities adequate to protect the pipeline system or gas combustion system must be used.

Note that for the purposes of this section and section 7.6.1, the terms knockout, knockout drum, scrubber, and separator are used interchangeably. The following requirements apply to all of these devices.

1) Liquid separation equipment must be provided in both temporary (including well test) and permanent flare and incinerator systems to prevent the carryover of liquid hydrocarbons, water, or other liquids.

2) Flare and incinerator separators must be designed in accordance with good engineering practice to remove droplets of 300 to 600 micron diameter and larger (see *ANSI/API Standard 521*).

   a) Designs must be based on the lowest density hydrocarbon liquids that could be released to the flare or incinerator system.

3) The flare and incinerator separators or knockout drums must be designed to have sufficient holding capacity for liquid that may accumulate as a result of upstream operations, such as hydrocarbon carryover, liquid slugs, and line condensation.

4) All flare and incinerator separators and knockouts must have visual level indicators and operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level under all operating conditions.

   a) For manually operated flares and incinerators (e.g., maintenance flares) where the flare or incinerator is normally isolated from the process stream (i.e., manual block valve), visual level indicators are not required when the operator has operating procedures in place to assess and mitigate the risk of liquid carryover. In the absence of an adequate operating procedure, the separator must be emptied before each flaring event.

      i) These operating procedures must be provided to the AER immediately upon request.

5) All flare and incinerator separators and knockouts must have high-level facility shutdowns or high-level alarms that can be responded to by the operator before liquid carryover. If impacts such as liquid carryover or unacceptable smoke emissions (see section 7.2) have occurred as a result of failure to control liquid level, both high-level facility shutdowns and high-level alarms must be provided.

   a) Where only manually operated flaring or incineration will occur (such as manual equipment depressurizing, handling hydrates, or for well cleanup and initial testing) and the operation is continuously attended, high-level facility shutdowns or high-level alarms are not required. Where personnel are not devoted to a flaring or incineration operation, the operation will not be considered to be continuously attended, despite a facility being continuously staffed.

6) High-level alarms and facility shutdowns must be installed on all flare and incinerator separators where liquid streams are directed to the separator for storage or where free liquids are contained in continuously combusted streams.

7) Flare and incinerator separators or knockout drums must be designed and be in accordance with AER *Directive 055: Storage Requirements for the Upstream Petroleum Industry*.

8) Design information on flare and incinerator system liquid separation equipment must be submitted upon request to the AER, including *Directive 056* facilities application review processes.

7.6.1 Exceptions to Separator Requirements

1) The AER does not require independent flare or incinerator separators in situations where the only vessels connected to the flare or incinerator are production separators equipped with a high-level shut down (HLSD) or equivalent devices or with a system that prevents liquids from entering the flare or incinerator. The following limitations apply to this exception:

    a) The HLSD must be configured to shut down and block in, but not depressurize, the facility. The HLSD trip level must be set so that adequate vapour-liquid separation is not impaired at maximum liquid level and vapour flow rates.

    b) If liquid carryover involving spills occurs around the flare or incinerator or if black smoke is formed, the licensee, operator, or approval holder must install adequately sized flare or incinerator separators.

2) The AER does not require independent flare or incinerator separators for combustion devices that destroy trace vent gases emitted from gas dehydrators.

7.7 Backflash Control

Inadequately purged flare or incinerator systems may have enough oxygen present to support combustion. Backflash may occur when the linear velocity of the combustible mixture of gas and air in the system is lower than the flame velocity.

1) The licensee, operator, or approval holder must take precautions to prevent backflash using appropriate engineering and operating practices, including

    a) installing flame arresters between the point of combustion and the flare or incinerator separator, or

    b) providing sufficient flare header sweep gas velocities (i.e., purge or blanket gas) to prevent oxygen intrusion into the flare or incinerator system.

2) Check valves are not an acceptable form of backflash control.

3) Safe-work procedures must be in place to ensure complete purging of oxygen from flare or incinerator systems before ignition.

4) The licensee, operator, or approval holder must provide information on backflash controls to the AER upon request if the AER determines that there is a concern with the equipment or controls.

7.8 Flare and Incinerator Spacing Requirements

Licensees, operators, and approval holders must follow good engineering and safety practices in the layout of facilities. Despite liquid separation requirements, unexpected liquid carryover to flares and incinerators can happen. Adequate spacing of these devices from areas frequented by workers and from sources of combustible gas is prudent. A licensee, operator, or approval holder must consult fire protection codes and guidelines as part of facility design. Licensees, operators and approval holders must immediately report fires (both on and off lease) caused by flares or incinerators to the local field centre.

1) Flares and incinerators other than enclosed combustors must be located, as measured from the base of the stack, at least
   a) 50 m from wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours;
   b) 50 m from storage tanks containing flammable liquids or flammable vapours;
   c) 25 m from any oil and gas processing equipment. This does not apply to combustion devices that destroy trace vent gases, such as those emitted from gas dehydrators. These devices must be designed to prevent ignition of gas that may leak from surrounding equipment (e.g., combustion devices could be equipped with flame arresters); and
   d) 25 m from crude bitumen wells, storage tanks, or other sources of ignitable vapour, including lined earth excavations used to store waste oil at batteries regulated as bitumen sites.
2) Enclosed combustors, as measured from the base, must be located at least 10 m from
   a) wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours;
   b) storage tanks containing flammable liquids or flammable vapours;
   c) oil and gas processing equipment; and
   d) other sources of ignitable vapours.

Flare knockout drums and integral knockout drums are exempt from flare and incinerator spacing requirements provided they have no means to vent to the atmosphere.

The incinerator that combusts gas from the sulphur recovery process is not required to meet incinerator spacing requirements for sulphur plant process equipment (i.e., converters and condensers).

3) Flares and incinerators must be located, designed, and operated so that they are not a hazard to public property. They must be at least 100 m away from surface improvements and

surface developments as defined in *Directive 056* (except for surveyed roadways or road allowances, which must be 40 m from flares and incinerators).[19]

4) The area around flares and incinerators must be free of fire hazards. Flare or incinerator spacing and operating practices must comply with the *Forest and Prairie Protection Act*[20] and any regulations under that act.[21]

5) The licensee, operator, or approval holder also comply with the *Forest and Prairie Protection Regulations*, Part I (AR 135/72), in unforested areas where there is a fire hazard associated with flare and incinerator operations.

6) In certain circumstances, the AER Authorizations Branch may consider variances to AER flare and incinerator spacing requirements.

   a) The AER discourages variance requests for new facilities.

   b) Existing well site equipment spacing waivers are maintained.

   c) A licensee, operator, or approval holder requesting a spacing variance must first consult relevant codes and engineering practices and provide related information in support of the variance request.

7.9 Compliance with Fire Bans

Information on fire bans issued by AEP can be found at www.albertafirebans.ca, directly from local municipal districts, or by calling 1-866-310-FIRE (3473).

7.10 Noise

1) Flares and incinerators must be designed and operate in compliance with *Directive 038.*

7.11 Flare Pits

Flare pits must not be used at any facilities built after July 1, 1996. For facilities built before July 1996, the licensee, operator, or approval holder must meet the following requirements:

1) All existing flare pits must be decommissioned by December 31, 2015. Exemption requests for cryogenic flare pits must be submitted to the AER Authorizations Branch by December 31, 2015.

2) Produced liquids must not enter the pit, in accordance with section 8.080 of the *OGCR*.

3) Flaring of sour gas must comply with the *AAAQO*.

4) Gas containing more than 10 mol/kmol H_2S must not be flared in pits.

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[19] The 40 m spacing requirement applies to public road allowances and roads to which the public has open access. There is no spacing requirement for private licensee access roadways or private roadways on operating sites.

[20] *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended.

[21] As at the date of this directive, *The Forest and Prairie Protection Regulations*, AR 135/72.

5) The licensee, operator, or approval holder must conduct evaluations of solution gas flares for flare pits as described in sections 2.3 and 2.9 and implement the resulting decision.

6) Access restrictions and procedures must be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m^2.

7) If the facility is modified or if the facility increases its average annual production, the flare pit must be replaced with a flare stack.

8) The AER can require the licensee, operator, or approval holder to replace flare pits with flares systems if any part of the facility is in noncompliance.

9) Operation of flare pits must comply with the provisions of the *Forest and Prairie Protection Act*[22] and with any regulations under that act.[23]

7.12 Dispersion Modelling Requirements for Sour and Acid Gas Combustion

The following requirements apply to the combustion of sour gas in process equipment, such as steam generators and process heaters, as well as to flares and incinerators.

1) The licensee, operator, or approval holder must demonstrate, using dispersion modelling methods outlined in AEP's *Air Quality Model Guideline*, that SO_2 and H_2S emissions from the burning of sour and acid gas will not result in exceedance of the *AAAQO* if the gas contains the following amounts or more:

   - 10 mol/kmol H_2S, or
   - one tonne/day of sulphur emission rate during the event.

   A licensee, operator, or approval holder combusting gas below these concentrations and emission rates is encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from AEP under the *EPEA* may need more detailed evaluation. A licensee, operator, or approval holder should consult AEP directly in these instances.

2) Dispersion modelling must be done by qualified technical personnel using computer models and methodologies acceptable to AEP or, if appropriate, the method described in section 7.12 and appendix 7.

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[22] *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended.

[23] As at the date of this directive, *The Forest and Prairie Protection Regulations*, AR 135/72.

7.12.1 Modelling Approach

The definitions of screening and refined dispersion modelling assessments are in appendix 8.

1) The licensee, operator, or approval holder must

- select an appropriate model,
- be able to demonstrate that the model selected is appropriate and follows AEP accepted methodologies and standards, and
- use representative input parameters (e.g., flow rate, gas composition) within the model and be prepared to demonstrate that those parameters are representative.

7.12.2 Individual Source

1) Initial modelling may be conducted using the screening assessment provided in the AERflare.xls and AERincin.xls spreadsheets.

2) For a screening assessment, ambient air quality modelling must use

   a) stack-specific terrain extracted by the spreadsheets or from 1:50 000 topographical National Topographic System (NTS) maps,

   b) the point source (not flare) option,

   c) full screening meteorology,

   d) appropriate land use characteristics, and

   e) emission parameters as calculated by the AERflare.xls and AERincin.xls spreadsheets (e.g., velocity, diameter, and temperature inputs for dispersion modelling).

3) Modelling must address a full range of expected flow-rate conditions and may include the low, average, and maximum flow rate.

4) The selected flare or incinerator design must not result in ground-level SO_2 concentrations higher than those in the *AAAQO*.

   a) A refined assessment may be used if the screening assessment results in an impractical stack height.

   b) If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, the licensee, operator, or approval holder may consider

      i) using an air quality management plan (see appendix 7),

      ii) operating procedures and process controls to prevent emission rates or durations that would exceed the *AAAQO* (see sections 7.5, 7.12.4), and

      iii) adding gas to increase heat release and plume rise. As stated in section 7.4, proper flare stack height must be used to minimize gas consumption.

c) The risk-based criteria discussed in section 7.12.4 do not apply to continuous (nontemporary) sour gas combustion at permanent facilities.

7.12.3 SO_2 Cumulative Emissions Assessment

If predicted maximum hourly average ground-level concentrations for the individual continuous source are more than one-third of the *AAAQO* for SO_2, then the licensee, operator, or approval holder must conduct an assessment of cumulative effects of all routine SO_2 sources.

1) The following steps must be followed for cumulative emissions assessments:

   a) Identify the farthest downwind location where predictions exceed one-third of the hourly average *AAAQO* for SO_2 to define the radius of influence.

   b) Identify all other continuous sources of SO_2 within this radius of influence up to a maximum of 20 km; if no other sources of SO_2 are within the radius, no further modelling is required.

   c) Quantify SO_2 emissions from these other sources and obtain all necessary input data, such as stack height and other parameters (the licensee, operator, and approval holder must share related data with each other on a timely basis). Maximum hourly flow-rate conditions must be used for all sources in the radius of influence.

      i) In applications for a continuous source, other sources must be modelled at licensed emission rates.

      ii) SO_2 cumulative assessments are not required for nonroutine flaring, venting, and incineration (e.g., well test or planned maintenance blowdown).

   d) Model the cumulative effects of the SO_2 emission sources.

   e) If the sum exceeds the *AAAQO*, determine the appropriate stack height required to meet the *AAAQO*. All refined modelling must follow the methods outlined in the *Air Quality Model Guideline* (2013).

7.12.4 Temporary and Well Test Flaring Dispersion Modelling

This section applies to temporary events that may require a permit (as described in section 3) and well test flaring or incineration activities. These activities include well testing, well cleanup, well servicing, coalbed methane well testing, underbalanced drilling, and sour gas pipeline (as defined in *Directive 056*) blowdown through temporary flare or incinerator equipment. These activities exclude nonroutine flaring or incineration at permanent AER-licensed facilities.

1) The licensee, operator, or approval holder must complete either the flaring (AERflare.xls) or incinerator (AERincin.xls) spreadsheet.

2) Information on ambient air quality impact evaluations must be included in requests to burn sour gas or, if no permit is required, must be provided to the AER upon request. The

dispersion modelling within AERflare.xls or AERincin.xls may be sufficient if a screening assessment is adequate.

3) Sour gas flares and incinerators must be designed for the gas composition and flow rates of the situation for which there is a temporary permit (see section 7 for further information).

4) Equipment design or the operating procedures, or both, must address all modelled predictions that exceed the *Alberta Ambient Air Quality Objectives*, excluding predicted values that meet the risk-based criteria. The risk-based criteria only apply to temporary events.

   a) Risk-based criteria for temporary events allow limited exclusion of predicted ambient air quality results, provided that

      i) the 99th percentile predicted values at a receptor do not exceed the one-hour SO_2 Alberta ambient air quality objective, and

      ii) the 99.9th percentile predicted values do not exceed a predicted one-hour SO_2 ambient concentration of 900 micrograms (μg) per m^3.

      Note that whereas model predictions up to 900 $\mu g/m^3$ will be considered, actual exceedances of the *Alberta Ambient Air Quality Objectives* are never permitted.

   b) Risk-based criteria are incorporated into the flare and incinerator spreadsheets for screening modelling.

   c) If refined modelling is required to determine whether the temporary event meets the risk-based criteria, the refined modelling input files from the spreadsheet must be used.

   d) The AER Authorizations Branch will also consider use of the risk-based criteria in situations where air quality management plans (see appendix 7) are necessary to ensure compliance with the *Alberta Ambient Air Quality Objectives*.

      i) Air quality management plan decision criteria may be based on meteorological or ambient air quality monitoring data.

5) Concurrent temporary sour gas burning (i.e., multiple well test flaring/incinerating) must not occur within 20 km of each other unless a licensee can demonstrate that the cumulative emissions from flaring can meet the *AAAQO*.

6) Licensees must retain, for one year after the flaring/incineration event, information on dispersion assessments for flares or incinerators that require dispersion modelling but do not require a flaring permit (see section 3.3.2). This information must be provided to the AER Authorizations Branch upon request.

7.12.5 Nonroutine Flaring and Dispersion Modelling

This section applies to nonroutine planned and unplanned flaring from permanent flares. Temporary and well testing activities described in section 7.12.4 are not included here.

"Nonroutine flaring" applies to intermittent and infrequent flaring and incineration. There are two types of nonroutine flaring: planned flaring and unplanned flaring.

- Planned flaring—Flare events where the operator has control over when flaring will occur, how long it will occur and the flow rates. Planned flaring results from the intentional depressurization of processing equipment or piping systems. Examples of planned flaring include pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests. Note that well testing dispersion modelling criteria are addressed in section 7.12.4.
- Unplanned flaring—Emergency or upset operational activities closely associated with facility health and safety. Flare events where the operator has no control of when flaring will occur. There are two types of unplanned flaring upset flaring and emergency flaring.
  - Upset flaring occurs when one or more process parameters fall outside the allowable operating or design limits and flaring is required to aid in bringing the production back under control. Examples of upset flaring include: off-spec product, hydrates, loss of electrical power, process upset, and operation error.
  - Emergency flaring occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of upset flaring include PSV overpressure and emergency shutdown.

Figure 8 summarizes the process for managing the nonroutine flaring of sour gas.

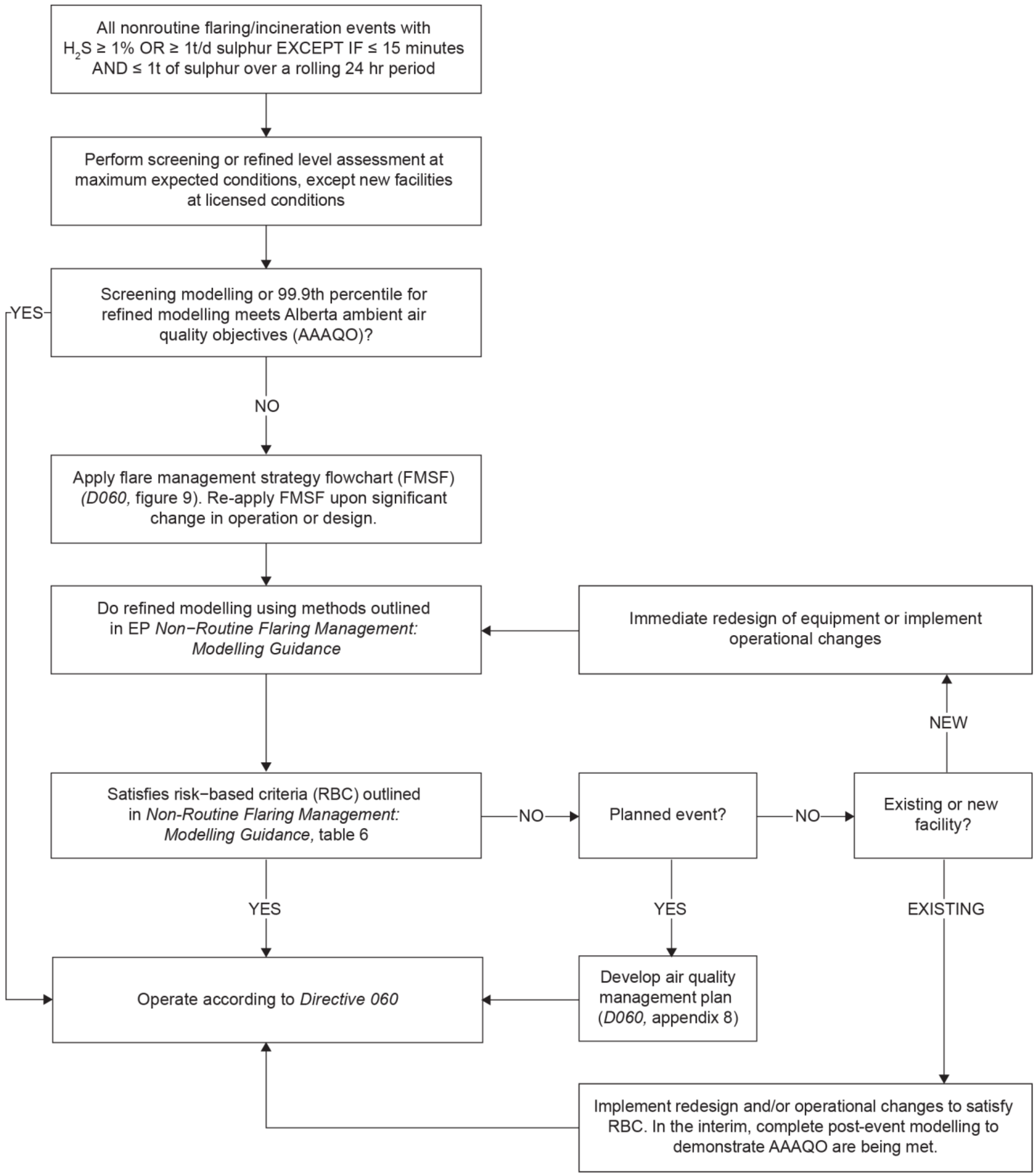


Figure 8. Comprehensive management of the nonroutine flaring of sour gas

1) The licensee, operator, or approval holder must evaluate impacts of nonroutine sour gas flaring on ambient air quality if

   a) it is proposed to burn sour gas containing 10 mol/kmol H_2S (1 per cent H_2S) or more, or

   b) 1 tonne of sulphur mass is released during the event or the day (for multiple releases).

Single nonroutine flare events that are predicted to be less than or equal to 15 minutes in duration and predicted to emit less than 1 tonne of sulphur over a rolling 24-hour period are exempt from modelling requirements.

2) For new permanent flare stacks the licensee, operator, or approval holder must meet nonroutine flaring dispersion modelling criteria effective immediately upon the sanctioning of this framework.

3) Unless the AER requires otherwise, where previous modelling reports of nonroutine flare events show compliance with the *AAAQO* using tools and methods no longer accepted by AEP (e.g., SCREEN3, RTDM, ISC3, AQMG, and AER low risk criteria), the facility can continue to operate as is. If any emission changes occur at the respective facility or if the AER requests that new dispersion modelling be conducted for any reason, the operator will apply the flare management strategy flowchart (figure 9) and will reassess dispersion modelling using current modelling methodology and tools.

4) For permanent flare stacks the licensee, operator, or approval holder must assess nonroutine flaring dispersion modelling criteria within the following timelines where facilities lack evidence of dispersion modelling or where facilities are unable to satisfy the *AAAQO* for nonroutine flaring events using tools and methods no longer accepted by AEP:

   a) Sour gas processing plants: March 22, 2017

   b) Compressor stations and oil and gas batteries: March 22, 2018

   c) Well sites and pipeline risers: March 22, 2020.

   d) If emissions change at existing AER-licensed facilities, the licensee, operator, or approval holder must reassess nonroutine flaring dispersion modelling criteria when a renewal or amendment is required.

   e) All processing facilities subject to the *Environmental Protection Enhancement Act – Activities Designation Regulation* must remodel upon renewal.

5) Initial screen modelling may be conducted using AERflare or AERincin or dispersion modelling methods outlined in AEP's *Air Quality Model Guideline*. If nonroutine refined modelling is required or if stack design is impractical, the licensee must apply the flare management strategy flowchart (figure 9) or equivalent, and dispersion modelling evaluations must be conducted using methodologies described in AEP's *Non-Routine Flaring Modelling Guidance.* The flare management strategy flowchart and refined modelling must be reapplied if facility operation or design changes significantly.

6) If modelling of worst-case unplanned flaring scenarios show 99.9th percentile hourly predicted concentrations in excess of the AER SO_2 sheltering-in-place or evacuation criteria from *Directive 071*, the licensee, operator, or approval holder must implement design or operational

changes such that risk-based criteria are met within three years of the assessment. In the interim, for each unplanned flaring event at the facility, the licensee, operator, or approval holder must do post-event dispersion modelling. (See section 7.12.5[11]).

7) If modelling of worst-case scenarios shows that the predicted 99.9th percentile hourly concentrations are lower than the AER SO_2 evacuation criteria from *Directive 071* and the predicted 90th percentile hourly concentration is higher than the *AAAQO* for SO_2, then for each unplanned flaring event at the facility, the licensee, operator, or approval holder must do post-event dispersion modelling. (See section 7.12.5[11]).

8) For planned flaring events, the licensee, operator, or approval holder must develop flare management plans that meet the risk-based criteria to ensure that the *AAAQO* are not exceeded, and implement them during flaring. It is acceptable for modelling to be based on actual flows and gas compositions, not licensed values.

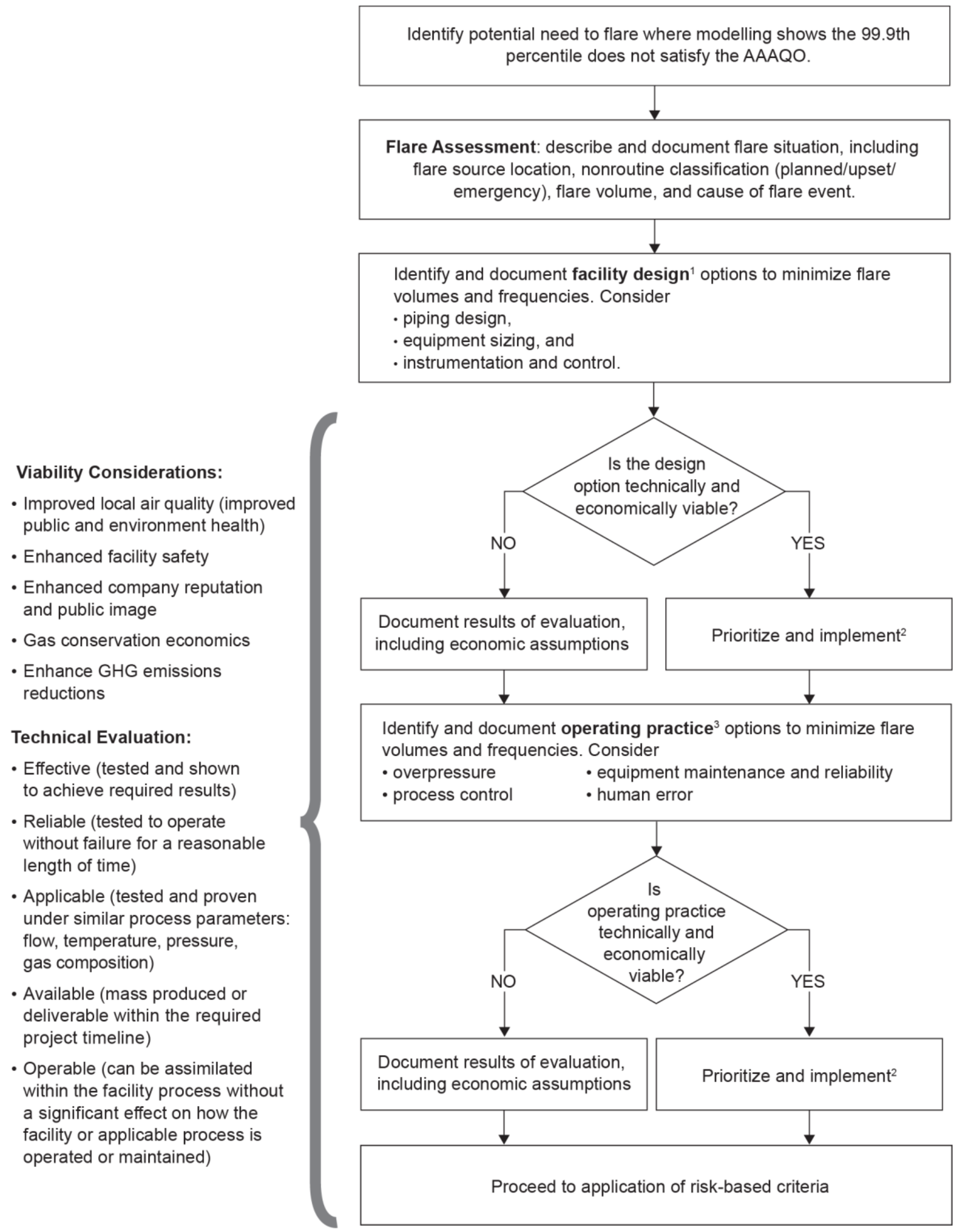
9) If refined modelling for nonroutine flaring is required, the licensee must not exceed the risk-based criteria maximum number of flaring hours per calendar year described in AEP's *Non-Routine Flaring Modelling Guidance* table 1. The licensee, operator, or approval holder must log all flaring events, including flare duration, volume, and rates.

10) If nonroutine flaring exceeds the risk-based criteria maximum number of flaring hours per year described in AEP's *Non-Routine Flaring Modelling Guidance* table 1 or if the event results in an exceedance of the *Alberta Ambient Air Quality Objectives* for SO_2, the licensee, operator, or approval holder must conduct post-event dispersion modelling (see section 7.12.5[11]) and contact the AER Authorizations Branch immediately.

11) If post-event modelling is required, the actual conditions must be used. If site-specific meteorological data during the event is not available, five years of meteorological data from a standard period is recommended using the AEP data set (www.albertamm5data.com/). One month per year must be modelled from the data set, centred around the month of the event.

12) If the AER Authorizations Branch determines that the dispersion modelling has not been completed in accordance with *Directive 060* requirements, the licensee, operator, or approval holder may be subject to a regulatory response.

13) The licensee, operator, or approval holder is not required to provide copies of nonroutine dispersion modelling or a flare management strategy flowchart to the AER unless requested. Upon request, the licensee, operator, or approval holder must provide the evaluation to the AER within five working days.



Notes

1 Section 5.2 of the CAPP *Best Management Practices for Facility Flare Reduction* provides a description of facility design considerations.

2 After prioritization, schedule for implementation in a staged process to ensure operational changes are implemented first, highest priority projects are implemented first, minimum disruption to current operations, adequate capital is available for implementation, and regulatory targets or objectives are achieved.

3 Section 6.2 of the CAPP *Best Management Practices for Facility Flare Reduction* provides a description of operational practice considerations.

Figure 9. Flare management strategy flowchart

8 Vent Gas Limits and Fugitive Emissions Management

Vent gas and fugitive emissions are sources of methane emissions in the province. This section includes requirements to meet the target set by the Government of Alberta to reduce methane emissions from the provincial upstream oil and gas sector 45 per cent by 2025 from 2014 levels.

In this section, depending on the context, "duty holder" means the holder of an approval under the *Oil Sands Conservation Act*, the holder of a licence or approval under the *Pipeline Act* or *Oil and Gas Conservation Act*, or the operator of a facility where a licence or approval is not required under the *Oil and Gas Conservation Act.*

Figure 10 illustrates how the methane emission sources subject to the requirements in this section have been categorized.

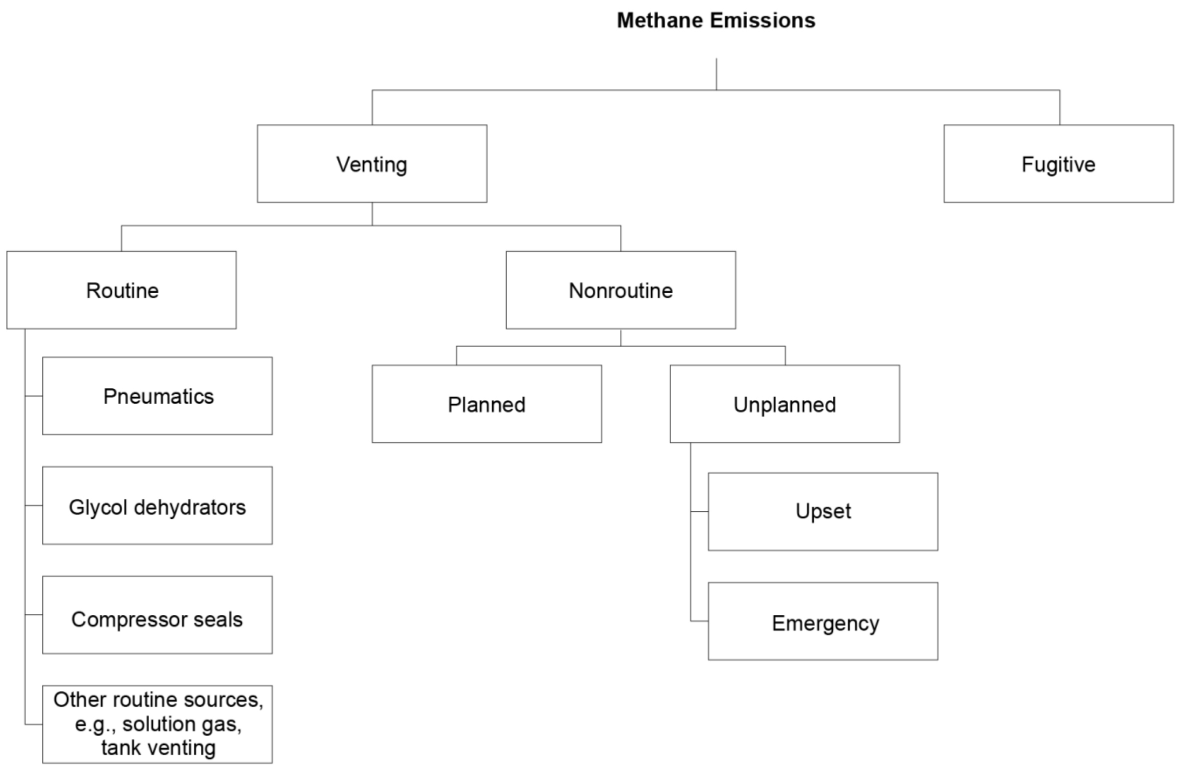


Figure 10. Methane emission sources covered under section 8

Routine venting is continuous or intermittent venting on a regular basis as part of normal operations. The AER recommends that duty holders eliminate all routine venting.

Nonroutine venting is intermittent and infrequent venting and can be planned or unplanned.

Fugitive emissions are the unintentional releases of hydrocarbons to the atmosphere.

For facilities operating under an *EPEA* approval or existing AER licence, the requirements in this section are in addition to any conditions in the *EPEA* approval or AER licence.

Unless otherwise stated, for operations in the Peace River area, requirements in this section are in addition to those set out in *Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area.*

8.1 Methane Reduction Retrofit Compliance Plan

Since the equipment retrofit and replacement requirements in section 8 may involve advance planning and investment by duty holders to ensure compliance on the date the requirements take effect, the AER will require duty holders to prepare a methane reduction retrofit compliance plan (MRRCP).

1) The duty holder must document an MRRCP that indicates how compliance with section 8.6 will be achieved.
2) The MRRCP must contain, at a minimum, the schedule to replace or retrofit existing equipment and the resources and budget allocated to ensure compliance with the requirements in section 8.6.
3) The MRRCP must be updated annually until January 1, 2023, to reflect material changes or progress made over the year according to the process in figure 11.
4) An executive of the duty holder must approve the MRRCP in writing, attesting that the MRRCP is designed to ensure compliance with the requirements in section 8.6.

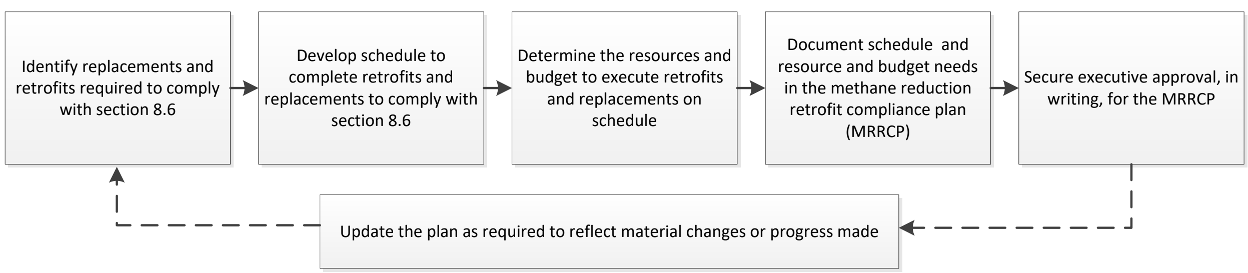


Figure 11. Process for developing and implementing a methane reduction retrofit compliance plan

8.2 Measurement and Reporting of Methane Emissions

Methane emissions may be quantified using continuous metering, periodic testing, or estimates based on accepted engineering practices. *Directive 017* identifies when vent gas from a site must be quantified using continuous metering or periodic testing, as well as acceptable testing methods. *Manual 015: Estimating Methane Emissions* provides guidance on how to estimate vent gas and fugitive emissions.

The annual methane emissions reporting period is the calendar year. The operator of record of a facility on December 31 is responsible for reporting over the entire reporting period, regardless of any changes in ownership during the reporting period.

Additional annual methane emission report requirements are set out in the corresponding vent gas limits and fugitive emissions management sections.

1) The operator of record for a facility that was active in a reporting period must electronically submit an annual methane emissions report to the AER by June 1 of the following calendar year or the next business day if the first is not a business day, or as otherwise directed by the AER. The first reporting period is 2019, and the first annual methane emissions report must be submitted to the AER by June 1, 2020.
2) Annual inventories must reflect equipment in place at the end of each reporting period.
3) For facilities that do not require a licence (such as small booster compressors), the venting and equipment must be reported to the nearest upstream reporting well, battery, or pipeline facility.

8.3 Overall Vent Gas Limit

Overall vent gas (OVG) is all routine and nonroutine vent gas.

1) The duty holder must limit OVG at a site to less than 15.0 10^3 m^3 of vent gas per month or 9.0 10^3 kg of methane per month.

In addition to complying with the OVG limit, the duty holder must comply with the vent gas limits in sections 8.4 to 8.9.

8.3.1 Exceptions

Vent gas from pneumatic devices, compressor seals, and glycol dehydrators are excluded from the OVG limit until January 1, 2023. Noncombustible gas, as described in section 8.9, is excluded from the OVG limit.

8.4 Defined Vent Gas Limit

Defined vent gas (DVG) is vent gas from routine venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators.

1) The duty holder must design and operate any site with first receipt or production on or after January 1, 2022, to limit the DVG emitted to less than 3.0 10^3 m^3 of vent gas per month per site or less than 1.8 10^3 kg of methane per month per site.

8.4.1 Reporting

1) The operator of record must include in the annual methane emissions report
   a) the annual volume of DVG emitted (m^3) by facility ID, and
   b) the corresponding mass of methane emitted (kg) by facility ID.

8.4.2 Exceptions

If the duty holder has opted to use the average vent gas rate for the crude bitumen fleet, as defined in requirement 8.5(1)(b), the methane emitted from the crude bitumen batteries is excluded from the DVG limit. Noncombustible gas, as described in section 8.9, is excluded from the DVG limit.

8.5 Vent Gas Limits for Crude Bitumen Batteries

This section applies to vent gas from crude bitumen batteries. Excluded from the vent gas limits for crude bitumen batteries are thermal in situ schemes and thermal in situ operations under *OSCA* and the *Oil Sands Conservation Rule*. Also excluded are batteries with either crude oil wells or crude bitumen wells that are within the Peace River area, as defined in *Directive 084*.

1) Effective January 1, 2022, the duty holder must limit vent gas to one of the following:

   a) From each site, to the DVG limit prescribed in section 8.4.

   b) From the crude bitumen fleet, to less than an average vent gas rate in each month of 1.5 10^3 m^3 per facility ID.

      The crude bitumen fleet in each month consists of facilities with non-zero production or vent volumes reported to facility IDs

      - with subtype codes 331, 341, and 342; or
      - with subtype codes 311, 321, and 322 that have at least one production string that
        - is reporting oil production from a pool with an assigned density greater than or equal to 920 kg/m^3 at 15 °C, or
        - has a well fluid status of bitumen.

Manual 011: How to Submit Volumetric Data to the AER defines the subtype codes.

The average vent gas rate in each month is calculated as follows:

$$\frac{\text{Sum of the vent volumes from the crude bitumen fleet}}{\text{Total number of facility IDs within the crude bitumen fleet}}$$

8.6 Equipment-Specific Vent Gas Limits

8.6.1 Vent Gas Limits for Pneumatic Devices

The requirements in this section apply to gas-driven pneumatic devices, including pneumatic instruments (e.g., controllers, switches, transducers and positioners) and pneumatic pumps.

1) The duty holder must prevent or control vent gas from pneumatic instruments installed on or after January 1, 2022.

2) The duty holder must ensure that pneumatic pumps installed on or after January 1, 2022, that operate more than 750 hours per calendar year do not emit vent gas.

3) Effective January 1, 2023, for level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must

   a) prevent or control vent gas, or

   b) evaluate the actuation frequency during normal operating conditions and for level controllers that actuate between 0 and 15 minutes, use a relay that has been designed to reduce or minimize transient or dynamic venting or adjust the actuation frequency to ensure that the time between actuations is greater than 15 minutes.

4) Effective January 1, 2023, for pneumatic instruments other than level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must

   a) prevent or control vent gas, or

   b) ensure that the instruments have a manufacturer-specified steady-state vent gas rate of less than 0.17 m^3/hr.

8.6.1.1 Exceptions

If a duty holder can demonstrate that a pneumatic instrument that vents gas is needed to maintain safe operating conditions or to achieve a necessary response time and that there is no other way of accomplishing this while still meeting venting requirement 1, 3, or 4 under section 8.6.1, then that instrument is exempted from the applicable requirement.

1) The duty holder must identify these exempt instruments with a weatherproof, readily visible tag.

8.6.1.2 Reporting

1) The operator of record must include in the annual methane emissions report the volumes from pneumatic instruments and pumps, by facility ID, of

   a) vent gas emitted (m^3), and

   b) corresponding mass of methane emitted (kg).

8.6.2 Vent Gas Limits for Compressor Seals

The vent gas limits in this section apply to vent gas from the seals of a reciprocating or centrifugal compressor that is rated 75 kW or more and is pressurized for at least 450 hours per calendar year.

8.6.2.1 Compressor Seal Testing

1) For any compressor seal that emits vent gas, the duty holder must test the seal at least every 9000 hours that it is pressurized.

2) The test must

    a) have a maximum single point uncertainty of ±10 per cent for a vent rate greater than 0.10 m^3/hr;

    b) have a maximum total back pressure of less than 1 kPa (includes the back pressure from the measurement device, piping, valving, and fittings) for a vent rate less than 1 m^3/hr;

    c) include all vents from the compressor seal;

        i) for reciprocating compressors, this includes piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) and compressor crankcase vent;

    d) include all compressor seals that emit vent gas (either by testing at a single common vent terminus point or at each vent of a compressor seal); and

    e) be conducted within 10 per cent of the average revolutions per minute and discharge pressure of the compressor. The average is to be based on the 168 pressurized hours prior to testing.

3) The duty holder must ensure that the testing point for each compressor seal that emits vent gas is accessible and clearly identified.

If a compressor seal has been replaced since the last test, it does not need to be retested until the next annual test.

Exception: Reciprocating compressors with piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) that are connected to control do not have to be tested annually. In these cases, gas emitted out of the compressor crankcase is a fugitive emission and subject to section 8.10.

8.6.2.2 Reciprocating Compressor Seals

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) on an individual throw. The reciprocating compressor crankcase vent is not subject to control requirements. Gas emitted from the crankcase of a controlled reciprocating compressor is a fugitive emission and subject to section 8.10. For uncontrolled reciprocating compressors, any gas emitted from the crankcase is vent gas from an RCS.

1) The duty holder must control vent gas from any seal on a reciprocating compressor installed on or after January 1, 2022, with four or more throws.

2) Effective January 1, 2022, the duty holder must limit vent gas from the RCS fleet to less than 0.35 m^3/hr/throw.

The RCS fleet consists of the duty holder's reciprocating compressors that are rated 75 kW or more, pressurized for more than 450 hours per calendar year, and either

a) were installed before January 1, 2022, or

b) were installed on or after January 1, 2022, and have fewer than four throws.

The vent gas from the RCS fleet is calculated as follows:

$$\frac{\sum_{i=1}^{n} v_i}{\sum_{i=1}^{n}(t_i \times c_i)}$$

where

n	=	total number of reciprocating compressors in the fleet
v	=	vent gas volume for the calendar year for the reciprocating compressor (m^3)
t	=	the number of hours per calendar year that the reciprocating compressor is pressurized
c	=	number of pressurized throws for the reciprocating compressor

3) Effective January 1, 2022, the duty holder must bring any RCS with a measured vent gas rate greater than 5.00 m^3/hr/throw to below 5.00 m^3/hr/throw within 30 days of the measurement date.

8.6.2.3 Centrifugal Compressor Seals

1) For centrifugal compressors installed on or after January 1, 2022, the duty holder must limit the vent gas rate to less than 3.40 m^3/hr/compressor. If the measured rate is not below this limit, the duty holder must take action to bring the rate below 3.40 m^3/hr/compressor within 90 days of the measurement date.

2) Effective January 1, 2022, for centrifugal compressors installed before January 1, 2022, the duty holder must limit the vent gas rate to less than 10.20 m^3/hr/compressor. If the measured rate is not below this limit, the duty holder must take action to bring the rate below 10.20 m^3/hr/compressor within 90 days of the measurement date.

8.6.2.3.1 Exceptions

Vent gas from engine or turbine starts and compressor blowdowns is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.2.

8.6.2.4 Reporting

1) The operator of record must include in the annual methane emission report
   a) the volume of vent gas emitted (m^3) from all compressor seals (including seals in compressors rated less than 75 kW and compressors pressurized for less than 450 hr/yr) by facility ID;
   b) the corresponding mass of methane emitted (kg) by facility ID;
   c) for each reciprocating or centrifugal compressor rated at least 75 kW and pressurized for more than 450 hr/yr, the following:
      i) compressor frame serial number or other unique identifier,
      ii) legal survey location (LSD-SC-TWP-RGWM),
      iii) authorization number and name of duty holder,
      iv) whether the equipment was installed before January 1, 2022, or on or after January 1, 2022,
      v) compressor type (reciprocating or centrifugal),
      vi) number of throws (if reciprocating),
      vii) seal type (dry or wet if centrifugal),
      viii) whether the piston-rod-packing vents and drains and distance-piece vents and drains are controlled,
      ix) annual vent gas volume (m^3), and
      x) annual pressurized time of compressor (hours).
4) The operator of record must base reported compressor seal vent gas volumes on
   a) a test result (may include metering), or
   b) an estimate based on accepted engineering practices.

When the compressor seal vent is tested, the test result is used to estimate the compressor seal vent gas volume for the period until the next test is conducted. If any seals are replaced between tests, an estimate based on accepted engineering practices can be used to estimate the compressor seal vent gas volume for the period from the seal replacement until the next test is done. For further guidance, see *Manual 015*.

8.6.3 Vent Gas Limits for Glycol Dehydrators

1) The duty holder must limit methane emissions from each glycol dehydrator installed or relocated on or after January 1, 2022, to less than 68 kg of methane/day.

2) Effective January 1, 2022, the duty holder must limit methane emissions from each glycol dehydrator installed or relocated before January 1, 2022, to less than 109 kg of methane/day.

8.6.3.1 Exceptions

Vent gas from glycol regenerators used in refrigeration processes is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.3.

8.6.3.2 Reporting

Refer to *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* for inventory requirements for active glycol dehydrators.

8.7 Additional Requirements

1) Provided that all other requirements in section 8 of this directive are met, section 8.031 of the *OGCR* permits the connection of pressure-relieving devices at oil production batteries to open tanks (i.e., "pop tanks").

2) Hydrocarbon products stored in atmospheric storage tanks at gas plants, compressor stations, and gas batteries must not have a true vapour pressure of more than 83 kilopascals (kPa) at 21.1°C if the tanks are vented to the atmosphere.

3) Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank-top gas, temporary, short-term venting is allowed at wells (e.g., for well unloading and liquid cleanup), facilities, batteries where conservation is in place (see partial equipment outages in table 1), and pipelines (for natural gas transmission systems, see section 6.3), with the following conditions:

    a) Gas must contain less than 10 mol/kmol H_2S and must not result in exceedances of the *AAAQO* outside the lease boundary.

    b) Gas must not contain any free hydrocarbon liquid (if free hydrocarbon liquids are present in the produced gas, a flare [or other gas combustion device] and liquid separation must be used).

    c) All liquids must be separated and contained in accordance with the storage requirements of *Directive 055*.

    d) Total gas volume must not exceed 2.0 10^3 m^3 and the duration must not exceed 24 hours.

    e) The duty holder must conduct notification in accordance with section 3.8 and table 2.

f) The AER field centre may consider alternatives to these requirements should special circumstances warrant. The licensee, operator, or approval holder must contact the appropriate AER field centre for approval of alternatives. For pipeline venting exemptions to these requirements, see section 6.2.

g) Short-term vent gas emissions must not exceed the OVG limit set out in section 8.3.

4) The licensee or operator must notify residents and the appropriate AER field centre of nonroutine venting within 500 m and must comply with *Directive 056* in respect of providing information about continuous flaring, incinerating, and venting to persons entitled it. Refer to section 3.8 for nonroutine venting notification requirements.

5) Vent gas must not constitute an unacceptable fire or explosion hazard and must comply with the spacing requirements in section 7.8. Venting must also not occur closer than

a) 25 m from any flame-type equipment (for diesel engines equipped with air intake shutoff device, see *Directive 036: Drilling Blowout Prevention Requirements and Procedures*),

b) 50 m from a wellhead for vent stacks other than surface casing vents, or

c) 25 m from a wellhead for heavy oil/bitumen well, storage tank, or other ignitable vapour including lined earth excavations used for waste oil storage.

6) A flame arrester or equivalent safety device, or proper engineering and operating procedures (e.g., sufficient sweep gas velocity) must be used on all vent lines connecting oil storage tanks to flare or incinerator stacks.

7) When equipment is used to control vent gas, the duty holder must design and operate control equipment to conserve or destroy at least 95 per cent of vent gas captured, with the equipment operating a minimum of 90 per cent of the time vent gas is emitted.

8.8 Requirements for Venting Gas Containing H_2S or Other Odorous Compounds

1) Gas containing more than 10 mol/kmol H_2S must not be vented to the atmosphere (excluding crude bitumen batteries). This includes gas off stock tanks, PSVs, and equipment blowdown systems.

a) Sour pressure-relief valves must be tied into flare systems if the gas contains more than 10 mol/kmol H_2S or result in off-lease H_2S odours.

2) At crude bitumen batteries, H_2S must not be vented to the atmosphere at a release rate greater than 0.04 m^3/hr.

a) Sour pressure-relief valves must be tied into flare systems if the total H_2S release rate is greater than 0.04 m^3/hr H_2S or results in off-lease H_2S odours.

3) Venting and/or fugitive emissions must not result in any H_2S odours outside the lease boundary. Venting and/or fugitive emissions must not result in any offensive hydrocarbon odours outside the lease boundary that, in the opinion of the AER, are unreasonable either because of their frequency, their proximity to surface improvements and surface development (as defined in *Directive 056*), their duration, or their strength.
   a) The AER recommends that PSVs and blowdown systems be connected to a flare system where such systems are installed.
4) Venting must not result in exceedances of the *AAAQO* outside the lease boundary.
5) Pressurized tank trucks or trucks with suitable and functional emission controls must be used when transporting sour fluids from upstream petroleum industry facilities.

8.9 Noncombustible Vent Gas Requirements

Release of inert gases such as nitrogen and carbon dioxide from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases may be vented to atmosphere subject to the following requirement:

1) Noncombustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient dilution gas to ensure destruction of odorous compounds.

8.10 Fugitive Emissions Management

The requirements in this section apply only to sites with active wells or facilities that are outside of the Peace River area. For operations within the Peace River area, the duty holder is to follow the fugitive emissions requirements in *Directive 084*.

8.10.1 Fugitive Emissions Management Program

1) The duty holder must have a documented fugitive emissions management program (FEMP).
2) The FEMP must be designed to reduce fugitive emissions, contain the elements listed in appendix 12, and be updated to reflect any changes to operations.

The duty holder may be directed to carry out additional actions to manage fugitive emissions if the AER determines that they are needed to mitigate potential risks to the environment or safety.

For further information on FEMPs, see *Manual 016: How to Develop a Fugitive Emissions Management Program*.

8.10.2 Fugitive Emissions Surveys

The AER may conduct fugitive emissions surveys or screenings. Surveys conducted by the AER do not replace any survey the duty holder is required to complete. If the AER detects fugitive emissions, it will direct the duty holder to make repairs.

8.10.2.1 Frequency

1) The duty holder must conduct fugitive emissions surveys at the frequency specified in table 4.

   The survey frequency for facilities is dictated by the facility subtype code, as set out in *Manual 011*, and not the equipment on site.

   Facilities that are designed to vent all received and produced gas do not require fugitive emission surveys.

2) The duty holder may adjust survey frequency to align with operational visits at sites where access is restricted. The duty holder must provide justification for the adjusted survey frequency to the satisfaction of the AER, upon request.

Table 4. Frequency of fugitive emissions surveys by equipment or facility type

Equipment or facility type	Facility subtype codes[1]	Frequency
Sweet gas plants	401	Triannually
Compressor stations (<0.01 mol/kmol H_2S in inlet stream)	601, 621[2]	
Liquid hydrocarbon storage tanks with vent gas control	N/A	
Produced water storage tanks with vent gas control	N/A	
Gas plants	402, 403, 404, 405	Annually
Straddle and fractionation plants	406, 407	
Compressor stations (≥0.01 mol/kmol H_2S in inlet stream)	601, 621[2]	
Battery and associated satellite facilities[3]	311, 321, 322, 331, 341, 342, 344, 345, 351, 361, 362, 363, 364	
Custom treating facilities	611, 612	
Terminals	671, 673	
Injection/disposal facilities	501, 502, 503, 504, 505, 506, 507	

1 Facility subtype codes are from *Manual 011*.

2 Subtype codes for compressor stations and gathering systems do not differentiate between sweet and sour gas processing. H_2S content of gas in the inlet stream determines the survey frequency for those facilities.

3 Wells linked to the facility subtype code but that are not located on the same site are excluded from the surveys.

8.10.2.2 Equipment and Methods

1) The duty holder must conduct fugitive emission surveys using one of the following:

   a) an organic vapour analyzer that detects hydrocarbons at a concentration of 500 ppm and is operated in accordance with the United States Environmental Protection Agency’s (EPA’s) Method 21: Determination of Volatile Organic Compound Leaks;

   b) a gas-imaging camera that can detect a stream of pure methane gas emitted at a rate of 1.0 gram per hour or less under controlled laboratory conditions and that is operated within six metres of the equipment being surveyed; or

   c) other equipment or methods that are equally capable of detecting fugitive emissions. However, the duty holder must assess equivalency and, upon request by the AER, demonstrate equivalence.

For further guidance on survey methods and equipment, see *Manual 016*.

8.10.2.3 Scope

1) The duty holder must survey the following:

   a) equipment components with hydrocarbon throughput;

   b) hydrocarbon gas–driven pneumatic devices;

   c) tank-top equipment, including thief hatches and gauge-board assemblies;

   d) surface casing vents and the area around the wellbore;

   e) equipment used to destroy vent gas, including burners, flare ignitors, pilots, and combustors; and

   f) equipment used to conserve vent gas, including vapour recovery units and vent gas capture systems.

8.10.2.4 Training and Equipment Maintenance

1) The duty holder must ensure that individuals conducting fugitive emission surveys are trained to use fugitive emissions survey equipment.

2) The duty holder must ensure that all equipment used to detect or quantify fugitive emissions is operated, serviced, and calibrated to the manufacturer's recommendations.

8.10.3 Fugitive Emissions Screenings

8.10.3.1 Frequency

1) The duty holder must ensure that annual fugitive emissions screenings are completed at all well sites except for

   - well sites that have been included in a fugitive emission survey that year,
   - well sites where all received and produced gas is vented, and
   - well sites with only oil sands evaluation wells or test holes approved under section 2.030 of the *OGCR*.

8.10.3.2 Methods and Equipment

1) The duty holder must conduct fugitive emissions screenings using one of the following:

   a) audio, visual, or olfactory methods;

   b) soap solution;

   c) other methods or equipment that is capable of detecting fugitive emissions, such as unmanned aerial vehicles or truck mounted sensors; or

   d) fugitive emissions survey methods and equipment.

   For guidance on screening methods and equipment, see *Manual 016*.

8.10.3.3 Training

1) The duty holder must ensure that individuals completing fugitive emissions screenings are trained to identify common sources of fugitive emissions.

8.10.4 Repairs

1) The duty holder must repair sources of fugitive emissions or take other action to eliminate fugitive emissions within 24 hours of identification if fugitive emissions

   a) are causing off-lease odours,

   b) are the result of a failed pilot or ignitor on a flare stack, or

   c) have the potential to cause safety issues.

2) The duty holder must repair all other sources of fugitive emissions or take other action to eliminate fugitive emissions within 30 days unless any of the following applies:

   a) A major shutdown is required to complete the repair and there are no safety issues.

      - Repair at the next planned shutdown or as directed by the AER.

   b) The fugitive emissions, measured using US EPA Method 21, have a hydrocarbon concentration less than 10 000 ppm.

      - No repair is required; however, these emissions must be quantified at each subsequent survey until the source is repaired.

   c) The fugitive emissions are from surface casing vent flow or gas migration.

      - Manage in accordance with the timelines in *Interim Directive 2003-01*.

8.10.4.1 Repair Confirmation

1) The duty holder must confirm the integrity of any repair within seven days of the component being brought back into service.

8.10.4.2 Tracking Sources of Fugitive Emissions for Repair

1) The duty holder must track the source of fugitive emissions for subsequent repair unless the repair is conducted immediately upon emissions detection.

The AER recommends that a duty holder physically tag a source that needs to be repaired and remove the tag once the integrity of the repair has been confirmed.

8.10.5 Reporting

1) The operator of record must include in the annual methane emissions report

   a) the volume of fugitive emissions (m^3) by facility ID, including any additional volume detected during an AER survey;

   b) the corresponding mass of methane emitted (kg) by facility ID; and

c) for any fugitive emissions site survey, tank survey, or well screening during the reporting period,

    i) the type of survey or screening (site survey, tank survey, or well screening),

    ii) the date the survey or screening was completed (YYYY/MM/DD) per site by facility ID, and

    iii) the number of identified sources of fugitive emissions per site by facility ID.

8.10.6 Alternative Fugitive Emissions Management Program

The AER will consider innovative and science-based alternatives to the fugitive emissions management program prescribed in this directive. Alternative programs may incorporate the use of various technologies such as unmanned aerial vehicles, vehicle-mounted sensors, and continuous monitoring devices to detect, track, repair, and report fugitive emissions.

1) If a duty holder wishes to use an alternative FEMP, the duty holder must submit a proposal to the AER for review and possible approval.

2) The duty holder must follow the requirements in sections 8.10.2 and 8.10.4 until its alternative program is approved.

8.11 Methane Emissions Record Keeping

1) Duty holders must retain records of the following for four years from the date they were created, unless otherwise noted, and provide them to the AER upon request:

    a) Calculations, by site, used to determine the monthly volume and monthly mass of methane from each of the sources below:

    - defined vent gas,
    - instruments and pumps,
    - compressor seals,
    - glycol dehydrators, and
    - fugitive emissions.

    In addition,

    - the hours of equipment usage or activity rates used in the monthly calculations, and
    - the supporting information, such as gas compositions, equipment test results, equipment or component numbers, gas density, conversion factors, and emission factors used in the monthly calculations.

If records are generated for compliance with *Directive 007: Volumetric and Infrastructure Requirements* or section 10 of this directive, the *Directive 007* records retention requirements and section 10 requirements supersede this requirement.

b) For fugitive emissions,

   i) the FEMP that is in effect,

   ii) sites where access is restricted and the reason for the restricted access,

   iii) completed training programs and valid certifications for all individuals conducting fugitive emission surveys and screenings, and

   iv) survey and screening results containing the information set out in appendix 13.

c) Inventory, updated annually, of pneumatic instruments and pumps that emit vent gas, including

   i) tracking identifier or serial number,

   ii) legal survey location (LSD-SC-TWP-RGWM) and facility ID,

   iii) installation or modification date,

   iv) make and model,

   v) device type (categorize as pump, level controller, non-level controller),

   vi) for level controllers that vent gas, the actuation frequency, and

   vii) for instruments that are exempt under section 8.6.1.1, the reason for the exemption (safety or response time).

d) Documentation that demonstrates that control equipment meets the requirements for vent gas control in section 8.7.

e) The MRRCP that is in effect.

f) For sites with first production or equipment installed before January 1, 2022, the dates of equipment changes for vent gas emissions management.

g) The RCS fleet average vent gas rate calculations.

h) Inventories of reciprocating and centrifugal compressors rated at least 75 kW, including

   i) compressor frame serial number or other unique identifier,

   ii) compressor power rating (kW),

   iii) legal survey location (LSD-SC-TWP-RGWM) and facility ID,

   iv) whether the equipment was installed before or after January 1, 2022,

   v) licence number and licensee,

vi) compressor type (reciprocating or centrifugal),

vii) number of throws (if reciprocating),

viii) seal type (dry or wet if centrifugal),

ix) whether seal vent is controlled or uncontrolled,

x) control device operating time, where applicable,

xi) compressor seal change-out date,

xii) the number of hours monthly a compressor was pressurized,

xiii) compressor seal test results, in m^3/hr,

xiv) compressor seal test dates, and

xv) the type of equipment used for the compressor seal test.

9 Sulphur Recovery Requirements and Sour Gas Combustion

Certain types of oil production, gas gathering, and nonassociated gas battery facilities can have significant sulphur emissions from combustion (by flaring, incinerating, or use as equipment fuel) of sour solution gas, from low-pressure produced water flash-gas, and from flaring of glycol dehydrator vent gas. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions from combustion of sour or acid gas.

1) Guidelines in *ID 2001-03* apply to sour gas plants and other upstream petroleum facilities such as oil production batteries, gas batteries, and pipeline facilities.

2) For in situ bitumen sites, the sulphur recovery requirements in table 1 of *ID 2001-03* apply. The sulphur inlet used to determine the sulphur recovery requirement in table 1 is based on total sulphur emissions from combustion of sour produced gas as fuel or by flaring or incineration divided by the number of days over a calendar quarter-year.

9.1 Sulphur Recovery Exemption at Solution Gas Conservation Facilities

The AER and AEP may deviate from sulphur recovery requirements in circumstances where sulphur emissions would be minimal and sulphur recovery would render gas conservation uneconomic.

Solution gas conservation clustering schemes that have a total inlet sulphur of between 1 and 5 tonnes/day may be considered for flexibility by AEP and the AER in the application of *ID 2001-03.* Provisions for deviations from the sulphur recovery guidelines are in section 4 of *ID 2001-03*.

1) The licensee or operator must apply to the AER for a variance from the sulphur recovery guidelines as part of related production project applications submitted to the AER. The application must take the form of a nonroutine *Directive 056* application, and applicants must indicate on the application that the facility will NOT comply with the requirements of *Directive 060*.

2) The licensee or operator must demonstrate to the AER, using the methodology in section 2.9, that implementing sulphur recovery would make the gas plant uneconomic.

   a) If gas production with sulphur recovery is economic, the licensee or operator must implement sulphur recovery.

3) The licensee or operator must demonstrate that revenues and cost estimates are reasonable.

   a) Capital cost estimates for sulphur recovery must be based on appropriate technologies. The licensee or operator must identify cost-effective processes suited to the facilities in question.

   b) Information on the following must be available to the AER upon request:

   i) volumes of gas available, including assessment of clustering other gas sources in the area

   ii) incremental energy (e.g., fuel gas) requirements for gas compression and processing related to gas sweetening

   iii) incremental energy (fuel gas) requirements for sulphur recovery processes

   iv) H_2S concentration of gas, along with expected average sulphur emissions and variability of sulphur emissions

   v) information on technology selection and costs for equipment (e.g., compression), gas gathering systems, and sulphur recovery processes. Note that the economic evaluation is based on incremental costs of gas conservation; therefore, equipment costs related to oil production, processing, and transportation must not be included

4) The licensee or operator must consult with residents within the radius set out in *Directive 056*, specifically explaining that a variance of the sulphur recovery guidelines is being applied for. Any objections must be disclosed in related facility applications.

5) The AER and AEP will consider the scope of the production project, the duration of the sulphur emissions, and the views of the local public in making decisions on applying the sulphur recovery guidelines.

   a) The existing processes used for *EPEA* approvals for sour gas processing plants and for AER approvals will be used to measure public acceptance of any proposals. If there are no unacceptable impacts and nearby residents do not object, meeting the sulphur recovery guidelines may not be required for solution gas facilities.

   b) The AER does not allow multiple nonsulphur-recovery sour operating sites in close proximity where it is practical to consolidate the facilities in one location and install sulphur recovery.

      i) Sour gas facility proliferation guidelines in *ID 2001-03*, section 6, stipulate how the AER will assess this matter.

6) The variances do not apply to sour gas production and processing facilities handling primarily nonassociated gas.

10 Measurement and Reporting

Requirements for measuring and reporting volumes of gas flared, incinerated, and vented are provided in *Directive 017: Measurement Requirements for Oil and Gas Operation*, *Directive 007: Volumetric and Infrastructure Requirements*, and the *OGCR*.

10.1 Flaring, Incineration, and Venting Records (Logs)

1) The licensee, operator, or approval holder must maintain a log of flaring, incineration, and venting events and respond to public complaints in order to comply with release reporting requirements.
   a) Release reporting requirements are defined in *IL 98-01* and AEP's *Release Reporting Guideline*.
   b) Logs must include information on complaints related to flaring, incineration, and venting and how these complaints were investigated and addressed.
   c) Logs must describe each nonroutine flaring, incineration, and venting incident and any changes made to prevent future nonroutine events from occurring.
   d) Logs must include the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), rates, and volumes for each incident.
   e) Logs must be kept for at least 12 months.
2) Flaring, incineration, and venting records must be made available to the AER upon request for each production facility, pipeline, and gas processing facility where flaring, incineration, and venting occur.
   a) A licensee, operator, or approval holder may retain logs for remote or semi-attended facilities at a central location (e.g., a regional office) where public complaints related to the facility in question would normally be received.
3) In situations governed by temporary flaring/incineration permits, a sour gas flaring/incineration data summary report (see appendix 6) must be completed in full and submitted to the AER Authorizations Branch within three weeks of the flaring/incineration completion date.

Appendix 1 References and Contacts Cited

AER Documents*

Oil and Gas Conservation Rules

Directive 007: Volumetric and Infrastructure Requirements
Directive 008: Surface Casing Depth Requirements
Directive 017: Measurement Requirements for Oil and Gas Operations
Directive 036: Drilling Blowout Prevention Requirements and Procedures
Directive 037: Service Rig Inspection Manual
Directive 038: Noise Control
Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators
Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices
Directive 055: Storage Requirements for the Upstream Petroleum Industry
Directive 056: Energy Development Applications and Schedules
Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs
Directive 066: Requirements and Procedures for Pipelines
Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry

Interim Directive (ID) 91-03: Heavy Oil/Oil Sands Operations
ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta
ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Venting Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements

Informational Letter (IL) 98-01: A Memorandum of Understanding Between Alberta Environment and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response

AERflare.xls and AERincin.xls spreadsheets
AERflare: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities
ABflare: A Refined Air Quality Dispersion Model for Evaluating Non-routine Flaring for Sour Gas Facilities

ST13A: Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics
ST13B: Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics
ST13C: Alberta Gas Gathering System Activities—Monthly Statistics
ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data
ST60B: Upstream Petroleum Industry Flaring and Venting Report

Alberta Energy Document

Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program

Alberta Environment and Parks Documents

Air Quality Model Guideline
Alberta Ambient Air Quality Objectives and Guidelines
Environmental Protection and Enhancement Act
Non-routine Flaring Management: Modelling Guidance
Release Reporting Guideline 1028-F

Alberta Utilities Commission Document

Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations

Other Documents

Alberta Pressure Equipment Safety Regulations, Alberta Safety Codes Act, The Pressure Equipment Safety Authority (AR 49/2006)
ANSI/API-521, Pressure-Relieving and Depressuring System, American Petroleum Institute
Clean Air Strategic Alliance (CASA), 1998, Management of Routine Solution Gas Flaring in Alberta, Report and Recommendations of the Flaring Project Team (Edmonton, Alberta)
CAPP, 2013, Sour Non-routine Flaring Framework
CAPP, 2006, Best Management Practices for Facility Flare Reduction

(continued)

* AER documents are available on the AER website at www.aer.ca and from AER Order Fulfillment, Suite 1000, 250 – 5 Street SW, Calgary AB T2P 0R4; telephone: 1-855-297-8311 (option 2); fax: 403-297-7040; email: InformationRequest@aer.ca.

Other Documents (continued)

CASA, 2002, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team (Edmonton, Alberta)

CASA, 2004, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Recommendations for Coal Bed Methane Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Review of Well Test Time Limits Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

Canadian Standards Association, 2016, CSA Z620.1: Fugitive and Vented Emissions for Petroleum and Natural Gas Industry Systems

Consumer Price Index forecast, Government of Alberta, Department of Finance website: www.finance.gov.ab.ca

Engineering and Geoscience Professions Act, RSA 2000 c. E-11

Forest and Prairie Protection Act, RSA 2000 c. F19

Forest and Prairie Protection Regulations Part I and II (AR 135/72)

GLJ Petroleum Consultants Limited, *Commodity Price Forecast*, “Natural Gas and Sulphur Price Forecast Table”

Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team, CASA

GPSA Engineering Data Book (13th edition), Gas Processors Suppliers Association

Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, CAPP

Industry Recommended Practice (IRP) Volume 4-2000/02: Well Testing and Fluid Handling, Canadian Petroleum Safety Council

United States Environmental Protection Agency (US EPA), Method 21: Determination of Volatile Organic Compound Leaks

PTAC Alberta Upstream Petroleum Research Fund Terms of Reference

AER Contacts

Authorizations Branch: 403-297-6179

Field Centres
- Bonnyville: 780-826-5352
- Drayton Valley: 780-542-5182
- Edmonton (formerly St. Albert): 780-642-9310
- Grande Prairie: 780-538-5138
- High Level: 780-926-5399
- Medicine Hat: 403-527-3385
- Midnapore: 403-297-8303
- Red Deer: 403-340-5454
- Wainwright: 780-842-7570

Regional Offices

Fort McMurray: 780-743-7214

Slave Lake: 780-843-2050

Appendix 2 Definitions of Terms as Used in *Directive 060*

Acid gas

Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), total reduced sulphur compounds, and/or carbon dioxide (CO_2).

Active facility

A facility that has reported an operation (volumetric activity) to Petrinex in the last 12 calendar months or is a nonproduction reporting facility linked to an active facility.

Active well

A well that has reported an operation (production or injection) to Petrinex in the last 12 calendar months or is classified as an observational well by the AER.

Associated gas

Gas that is produced from an oil or bitumen reservoir. This may apply to gas produced from a gas cap or in conjunction with oil or bitumen.

Carbon conversion efficiency (CCE)

The CCE quantifies the effectiveness of a device to oxidize hydrocarbons and is the relative conversion of carbon compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt hydrocarbons (hydrocarbon [HC] measured as methane [CH_4]) and other partially oxidized carbon compounds, such as carbon monoxide (CO) in the exhaust. CCE is reported as the percentage of carbon in the fuel that is converted to CO_2 and is obtained from

$$CCE = \frac{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel\ Converted\ to\ CO_2}{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel}$$

With this definition, the mass and molar efficiency are the same. An adjustment must be made if there is CO_2 in the inlet stream, as it does not react. The adjustment depends on the fraction of $CO_{2,fuel}$ and hydrocarbons $C_X H_{Y,fuel}$ in the gas stream entering the device and the number of carbon moles (X) per molecule of hydrocarbon. CCE can be determined from exhaust and fuel concentration measurements using

$$CCE = \frac{CO_{2,stack} - (CO_{2,fuel} / (X\, C_X H_{Y,fuel}))(CO_{stack} + HC_{stack})}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

This equation reduces to the following familiar expression if the inlet does not contain CO_2 ($CO_{2,inlet} = 0$):

$$CCE = \frac{CO_{2,stack}}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

Clustering

The practice of gathering the solution gas from several flares or vents at a common point for conservation.

Combustion efficiency (CE)	The CE quantifies the effectiveness of a device to fully oxidize a fuel. Products of complete combustion (i.e., CO_2, H_2O, and sulphur dioxide [SO_2]) result in all of the chemical energy released as heat. Products of incomplete combustion (e.g., CO, unburnt hydrocarbons, other partially oxidized carbon compounds, H_2S, and other reduced and partially oxidized sulphur compounds) reduce the amount of energy released. CE is reported as the percentage of the net heating value that is released as heat through combustion.
Component	A piece of equipment that has the potential to release hydrocarbons. Components include valves, connectors, pump seals, actuator seals, flow meters, pressure regulators, sampling connections, instrument fittings, engine and compressor crankcase vents, sump and drain-tank vents and covers, blowdown system vents, open-ended valves and lines, pressure vacuum relief valves, and gauge-board assemblies.
Condensate	Refer to *Oil and Gas Conservation Act.*
Conservation	The recovery of solution gas for use as fuel for production facilities, other useful purposes (e.g., power generation), sale, or beneficial injection into an oil or gas pool.
Conservation efficiency	Conservation efficiency (%) = (Solution gas production – Flared – Vented) / (Solution gas production) × 100
Conserving facility	Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.
Control	For the purpose of section 8, means to conserve or destroy vent gas. Standards for when equipment is used to control gas are found in section 8.7.
Crude bitumen	Refer to the *Oil and Gas Conservation Act*.
Crude bitumen battery	A crude bitumen battery is an oil battery with crude bitumen production that has a density of 920 kg/m^3 or greater at 15 degrees Celsius.
Crude oil	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen.
Crude oil battery	An oil battery with crude oil production excluding production that has a density of 920 kg/m^3 or greater at 15 degrees Celsius.
Defined vent gas	Vent gas from routine venting, excluding from pneumatic devices, compressor seals, and glycol dehydrators.

Duty holder In section 8, depending on the context, means the holder of an approval under the *Oil Sands Conservation Act*, the holder of a licence or approval under the *Pipeline Act* or *Oil and Gas Conservation Act*, or the operator of a facility where a licence or approval is not required under the *Oil and Gas Conservation Act*.

Emergency flaring, venting, or incineration Emergency flaring, venting, or incineration occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of possible causes of emergency flaring, venting, or incineration include pressure safety valve overpressure and emergency shutdown.

Facility Refer to the *Oil and Gas Conservation Act.*

Facility ID As defined in *Directive 047*, a unique facility identification code, with 4 letters and 7 numbers (e.g., ABWP1234567), assigned by Petrinex to each facility.

Flare gas Gas that is combusted in a flare or incinerator at upstream oil and gas operations. Types of gas, if combusted in a flare or incinerator (including an enclosed combustor), that must be reported as flare gas include the following:

- waste gas;
- pilot gas;
- dilution and makeup gas added to a flare gas stream before flaring or incineration;
- acid gas (routine and nonroutine);
- blanket gas, purge gas, and sweep gas;
- gas used to operate pneumatic devices (pneumatic instruments, pumps, and compressors starters);
- gas from dehydrator still columns;
- gas produced during well completions;
- gas produced during well unloading operations; and
- gas that is flared or incinerated as a result of equipment failures or plant upsets.

Fuel gas Gas that is combusted and the released energy is used in upstream oil and gas operations. Types of gas that must be reported as fuel gas include gas burned by the following:

- engines,
- catalytic heaters and other building heaters,
- process vessel burners,
- sulphur recovery unit reaction furnaces,
- line heaters, and
- thermoelectric generators.

Fugitive emissions Unintentional releases of hydrocarbons to the atmosphere.

Fugitive emissions screenings	Site-wide evaluations where the primary purpose is to identify fugitive emissions (e.g., from open thief hatches). These are less comprehensive than fugitive emission surveys.
Fugitive emission surveys	Site-wide evaluations that use equipment-based methods to detect and identify sources of fugitive emissions for repair. These surveys are considered comprehensive evaluations that can assist in reducing both small volumes and large volumes of fugitive emissions.
Gas battery	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H_2S scavenging where <0.1 tonne/day of sulphur is being treated, line heating, or other gas handling functions prior to the delivery to market or other disposition. This does not include gas processing equipment that recovers more than 2 m^3/day of liquids or that processes more than 0.1 tonne/day of sulphur.
Gas processing plant	A system or arrangement of equipment used for the extraction of H_2S, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigerant, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no H_2S or SO_2.
Makeup gas	Raw or processed gas that is added to another gas stream in order to maintain an adequate heating value during flaring or incineration.
Measurement	A procedure for determining a value for a physical variable. This may include metering, testing, estimating, or calculating.
Metering	To measure using a meter.
Nonassociated gas	Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).
Nonroutine flaring, venting, incineration	“Nonroutine” applies to intermittent and infrequent flaring, venting, or incineration. There are two types: planned and unplanned.
Oil battery	A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement prior to the delivery to market or other disposition.
Operator	Refer to definition in the *Oil and Gas Conservation Act*.

Operator of record The person or organization that keeps records and submits production reports to Petrinex or the AER for a reporting facility ID, whether or not that person or organization is the sole licensee or approval holder for all facilities or wells that are part of that reporting facility ID.

Planned flaring, venting, or incineration Flaring, venting, or incineration where the operator has control over when and for how long it will occur and also has control over release rates. Planned flaring, venting, or incineration results from the intentional depressurization of processing equipment or piping systems. Planned flaring, venting, or incineration may occur during pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests.

Pneumatic instrument A pneumatic device, powered by pressurized gas, used for maintaining a process condition such as liquid level, pressure, or temperature. Includes positioners, pressure controllers, level controllers, temperature controllers, and transducers.

Pneumatic pump A pneumatic device that uses pressurized gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm. Includes methanol and chemical injection pumps, but does not include energy exchange pumps.

Qualified technical professional A person holding an accredited professional qualification and acting within that person's professional scope of practice.

Risk-based criteria Refer to AEP's *Non-Routine Flaring Management Modelling Guidance* for the purpose of *Directive 060* only.

Routine flaring, venting, incineration "Routine" applies to continuous or intermittent flaring, venting, and incineration that occurs on a regular basis due to normal operation. Examples of routine flaring include glycol dehydrator reboiler still vapour flaring, tank vapour flaring, flash tank vapour flaring, and solution gas flaring. Routine venting can include gas from

- production casing vents,
- process vents,
- tank vents,
- blanketing,
- online gas analyzer purge vents,
- pneumatic devices, and
- desiccant dehydrator regeneration vents and membrane dehydrator purge vents.

Schools All public, private, and charter preschool, elementary, and secondary schools. This includes First Nations and Métis schools, but does not include a parent-provided home education program.

Screening assessment	This is the quickest and simplest dispersion modelling approach. Screening assessments usually provide a conservative (worst-case) estimate of downwind concentrations. If exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* are predicted by a screening assessment, a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the *Alberta Ambient Air Quality Objectives and Guidelines*.
Site	The area defined by the boundaries of a surface lease for upstream oil and gas facilities and wells (pads counted as one lease).
Solution gas	All gas that is separated from condensate, oil, or bitumen production.
Sour gas	Natural gas, including solution gas, containing H_2S.
Source	All gas flared, incinerated, or vented from a single operating site, such as an oil battery or multiple-well pad.
Sulphur conversion efficiency (SCE)	The SCE quantifies the effectiveness of a device to oxidize sulphur and is the relative conversion of sulphur compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt H_2S, other reduced sulphur compounds (measured as H_2S), such as carbonyl sulphide and carbon disulphide (especially if present in the fuel), and other partially oxidized sulphur compounds, such as sulphur trioxide (SO_3) in the exhaust (measured as SO_3). SCE is reported as the percentage of sulphur in the fuel that is converted to SO_2 and is obtained from $$SCE = \frac{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel\ Converted\ to\ SO_2}{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel}$$ With this definition, the mass and molar efficiency are the same. SCE can be determined from stack gas concentration measurements using $$SCE = \frac{SO_{2,stack}}{(SO_{2,stack} + SO_{3,stack} + H_2S_{stack})}$$
Sulphur emissions	All air emissions of sulphur-containing compounds, including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.
Sulphur recovery efficiency	Sulphur recovery efficiency = (sulphur produced + injected)/(sulphur produced + injected + sulphur emissions), where the sulphur emission is normally SO_2 expressed in sulphur equivalence. All values are units of mass.
Throw	The parts of a reciprocating compressor from the connecting rod to the cylinder. The number of throws on a compressor is equal to the number of connecting rods off the compressor crankshaft.

Unplanned flaring, venting, or incineration Emergency or upset operational activities closely associated with protecting the integrity of the facility and protecting safety. The operator has no control over when these activities will occur. There are two types of unplanned flaring, venting, or incineration: upset and emergency.

Upset flaring, venting, or incineration Upset flaring, venting, or incineration occurs when one or more process parameters fall outside the allowable operating or design limits and flaring, venting, or incineration is required to aid in bringing the production back under control. Upset flaring, venting, or incineration may occur due to the production of off-spec product; the formation of hydrates; loss of electrical power; process upset; or operator error.

Vent gas Uncombusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas does not include fugitive emissions, but does include

- waste gas;
- gas used to operate pneumatic devices;
- gas from compressor seals, starters, and blowdowns;
- gas from facility upsets and emergency shutdowns;
- gas from dehydrator still columns;
- gas from production tanks, not including methanol and chemical tanks;
- gas released during pigging operations;
- gas produced during well completions;
- gas produced during well unloading volumes; and
- blanket gas.

Appendix 3 Abbreviations

10^3 m^3	thousand cubic metres
10^6 m^3	million cubic metres
AAAQO	Alberta Ambient Air Quality Objectives and Guidelines
AEP	Alberta Environment and Parks
AOF	absolute open flow
APEGA	Association of Professional Engineers and Geoscientists of Alberta
ASET	Association of Science and Engineering Technology Professionals of Alberta
AUPRF	Alberta Upstream Petroleum Research Fund
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CO_2	carbon dioxide
CSA	Canadian Standards Association
DVG	defined vent gas
EPAC	Explorers and Producers Association of Canada
EPEA	Environmental Protection and Enhancement Act
ESDV	emergency shutdown valve
FEMP	fugitive emissions management program
FIS	Field Information System
GOR	gas-to-oil ratio (gas:oil)
H_2S	hydrogen sulphide
HLSD	high-level shutdown
km	kilometre
kPa	kilopascal
mol/kmol	mole per kilomole
MJ	megajoule
MJ/m^3	megajoule per cubic metre
MRRCP	methane reduction retrofit compliance plan
MW	megawatt
NOWPP	New Oil Well Production Period
NPV	net present value
NRFTT	Non-routine Flaring Task Team
NTS	National Topographic System
OVG	overall vent gas
Petrinex	Canada's Petroleum Information Network
ppm	parts per million
PSV	pressure safety valve
PTAC	Petroleum Technology Alliance Canada
RCS	reciprocating compressor seal
SO_2	sulphur dioxide

Appendix 4 Background to *Directive 060*

Concerns about flaring prompted the Alberta Energy and Utilities Board (EUB; now the AER) and Alberta Environment (now Alberta Environment and Parks) to support Alberta Research Council research on flaring. Findings reported in 1996 suggested that the efficiency of flare stacks at destroying waste gas was not as high as originally thought and that various products of incomplete combustion were in flare emissions.

The EUB then consulted with stakeholders from industry, the public, and other government sectors and reviewed existing policies on solution gas conservation. CAPP brought the issue of flaring to the CASA board of directors in November 1996 and established the Flaring Project Team in February 1997 to develop recommendations to address potential and observed impacts of flaring. In its 1998 final report, *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team*, the Flaring Project Team recommended a framework for solution gas flaring management and a decision tree process for reducing flaring.

The EUB Implements the CASA Recommendations

In 1999 in the first edition of *Directive 060* (then called *Guide 60*), the EUB implemented the solution gas management framework (section 2), the decision tree process (section 2.3), and other CASA recommendations. The guide mandated firm, short-term solution gas flare reduction targets of 15 per cent and 25 per cent by the end of 2000 and 2001, respectively, relative to the 1996 revised baseline of 1340 10^6 m^3 per year; the guide also defined maximum limits on the total volume of solution gas that could be flared at individual sites if voluntary targets were not met.

In 2000, a new CASA team, the Flaring/Venting Project Team, convened to review progress made on the 1998 recommendations as well as make further recommendations on flaring, incineration, and venting. The result was the 2002 report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team*. The report said that implementation of the solution gas management framework and the flare reduction targets by the upstream petroleum industry had successfully resulted in a 53 per cent reduction in solution gas flaring relative to the 1996 baseline.

On the basis of that success, the Flaring/Venting Project Team recommended that a similar decision tree process be applied to solution gas venting, well test flaring, and facility flaring. The team recommended that a 50 per cent reduction target be maintained for all solution gas flaring in Alberta relative to the 1996 baseline. Additional reports and recommendations were put forward in September 2004 and in March and June 2005. These recommendations were implemented through a rewrite of *Directive 060* released in November 2006. Significant changes included changing the economic threshold of the feasibility test for solution gas conservation from a net present value of zero to −$55 000. Also, economic evaluations were no longer required for sites that flared, incinerated, or vented less than 900 m^3/day of solution gas. Another significant addition to the directive was the concept of a duration limit for well test flaring and incineration.

Canadian Association of Petroleum Producers' Recommendations

In 2004, CAPP established the Nonroutine Flaring Task Team (NRFTT) to review dispersion modelling requirements for intermittent and infrequent flaring. The NRFTT comprised government and industry. The CAPP document titled, *Sour Non-Routine Flaring Framework* outlines the new regulatory approach and comprehensive plan for managing nonroutine flaring as developed by the NRFTT, and the process that led to its development.

Work on further reducing flaring, incineration, and venting continues.

Focus on Methane Emissions

In 2015, the Government of Alberta directed the AER to design and implement requirements that result in a 45 per cent reduction of methane emissions from the upstream oil and gas sector by 2025 from 2014 levels. In 2016, the AER created a multistakeholder committee to provide recommendations to the AER on regulating methane emissions in the province. The committee had representatives from the Government of Alberta, the AER, industry, and environmental non-governmental organizations.

With consideration of the recommendations from the committee, the AER developed methane emissions reduction requirements in *Directive 060*. The requirements cover both vent gas and fugitive emissions.

A mandatory review of the methane emissions requirements will occur within three years of the requirements taking effect to determine if any adjustments are needed.

Ongoing Research

The AER supports the 2004 CASA recommendations for additional research so that Alberta can continue to move towards the use of practical flare combustion efficiency standards where flaring is necessary. The AER expects that industry will support and participate in the funding of continued research focusing on

- understanding the relationship between gas composition and combustion efficiency, including the effects of H_2S content;
- understanding the effects of flare stack design, including flare tips on combustion efficiency;
- reviewing the results of any field testing of combustion efficiency monitoring methodologies;
- improving estimates of the amounts of methane emitted; and
- testing new technologies for emissions detection and reduction.

The AER supports the Petroleum Technology Alliance's Alberta Upstream Petroleum Research Fund (AUPRF). AUPRF is an industry-sponsored fund supported by CAPP and the Explorer and Producers Association of Canada (EPAC). The objective of AUPRF is to provide an efficient and effective mechanism to coordinate, initiate, fund, complete and communicate on environmental research that is needed by the industry and government regulators to enable a prosperous upstream oil and gas industry that achieves socially and environmentally responsible recovery of Canada's petroleum resources through effective, market-driven collaboration. AUPRF supports practical science-based studies that develop credible and relevant information to address knowledge gaps in the understanding and management of high priority environmental and social matters related to oil and gas exploration and development in Alberta. Research reports are shared broadly with the oil and gas industry as well as with regulators, government agencies, and other stakeholders.

Appendix 5 Information for Permit Request to Flare or Incinerate in Exceedance of Flared or Incinerated Volume Allowance Threshold (600, 400, or 200 10^3 m^3 Exceedance)

If flared or incinerated volumes are expected to exceed the volume allowance threshold during temporary operations, more information must be submitted to the AER.

1) Underbalanced drilling requests must include the following information:
   a) an explanation and supporting documentation on how flaring or incineration rates are determined; possible sources of these estimates are
      i) offset well AOF tests, or
      ii) flaring or incineration rates from offset underbalanced drilling operations;
   b) the estimated time required to drill the well;
   c) if a well test is proposed, the total volume requested for the test.
2) For well tests that are expected to exceed the volume allowance threshold, the request must include the following information:
   a) A brief description of the development required to bring the well onto production (e.g., length and size of pipeline to tie in well, well site facilities, compression, gas processing facilities)
   b) The minimum recoverable reserves required for the well to be economic (minimum economic reserves)
   c) Details of the analysis used to determine the minimum economic reserves. Licensees may use simplified "netback" economics showing the current operating profit (revenues minus operating costs) to estimate the recoverable reserves required to pay out facility investment costs; alternatively, licensees may choose to present a more detailed economic analysis involving features such as discounted gas flow projections)
   d) The estimated recovery factor and surface loss for the pool
   e) The estimated initial reservoir pressure
   f) The amount of reservoir depletion being targeted by the test (the licensee must provide a brief description justifying this depletion in relation to the minimum economic reserve). The recommended maximum pressure depletion guidelines are
      i) 1 per cent of the first 5000 kPa of reservoir pressure, and
      ii) 0.5 per cent of the reservoir pressure above 500 kPa.

   For example, a maximum depletion guideline of 100 kPa is targeted for a reservoir with an initial pressure of 15 000 kPa.

g) Justification for pretest cleanup and servicing flaring or incineration if related volumes exceed 200 10^3 m^3

Note that an incremental volume of up to 200 10^3 m^3 may be added to the permit request in order to provide for pretest cleanup and servicing operations if these are needed to establish the minimum economic reserve without additional justification.

Appendix 6

Sour Gas Flaring/Incineration Data Summary Report

This form must be completed in full and submitted within three weeks of the flaring completion date or, in the event no flaring took place, within three weeks of the expiry date. Submit to

Alberta Energy Regulator
Authorizations Branch, Flaring Approvals
Suite 1000, 250 – 5 Street SW
Calgary, AB T2P 0R4
Fax: 403-297-2691 E-mail: Directive060Inbox@aer.ca

Sour Gas Flaring/Incineration Data Summary

Approval no:

Company:

Well name: Unique well identifier:

Approval issue date: Expiry date:

Volume of formation gas flared: Approved: 10^3 m^3 Actual: 10^3 m^3

Instantaneous flared gas flow rate:

Approved (max.): 10^3 m^3/d Actual (max.): 10^3 m^3/d Actual (avg.): 10^3 m^3/d

Actual fuel gas flared (if applicable): Volume: 10^3 m^3 Rate: 10^3 m^3

Number of H_2S analyses conducted: (Provide tester report.)

H_2S content of raw gas:

Approved (max.): % Actual (max.): % Actual (avg.): %

Total sulphur flared: tonnes [= 1.35592(%H_2S ÷ 100)(flared vol.)]

Flaring dates:

Management plan required? ☐ No ☐ Yes

Meteorological monitoring conducted? ☐ No ☐ Yes (If yes, provide electronic copy of monitoring report)

Air monitoring conducted? ☐ No ☐ Yes (If yes, provide electronic copy of monitoring report)

Exceedances of the Alberta ambient air quality objectives (H_2S or SO_2)? ☐ No ☐ Yes (If yes, provide comments)

Comments:

AER field centre notification date: Field centre contact:

Were there any problems while flaring? ☐ No ☐ Yes

If yes, was the field centre contacted? ☐ No ☐ Yes If yes, provide contact name:

Comments:

Company representative:

Phone no.: E-mail: Fax no.:

Signature:

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Appendix 7 Air Quality Management Plans for Temporary SO_2 Emissions

If exceedances of the risk-based criteria for SO_2 (see appendix 8) are predicted and it is not proposed that flare/incinerator design parameters be altered to mitigate the potential exceedances, approval may be granted by the AER if suitable control measures are in place. In such situations, an air quality management plan must be submitted with the temporary permit request. **The management plan must outline how predicted exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* will be avoided so that the risk-based criteria are met.**

The air quality management plan may include the following:

1) Restrictions during specific meteorological conditions that will limit or avoid operations under conditions that result in predicted exceedances.
    a) These atmospheric conditions may include
        i) time of day,
        ii) wind direction,
        iii) wind velocity, and
        iv) atmospheric stability.
    b) Meteorological monitoring may be used as a management plan based on a maximum one-hour rolling (i.e., any consecutive 60 minutes), with measurements taken at a frequency of no more than every 15 minutes (i.e., four measurements/hour).
2) The management plan must include specifications for locating meteorological monitoring equipment (if used). Wind monitoring devices must be elevated above the height of trees surrounding the site.
3) Restrictions that may be applied during unfavourable meteorological conditions.
    a) Operational restrictions in air quality management plans may include
        i) suspension of flaring or incineration operations,
        ii) reduction or increase of flaring or incineration rates, and
        iii) requirements that supplemental fuel gas meet a minimum heating value or exit velocity.
4) If a reduction in flaring or incineration rate or an addition of supplemental fuel gas is proposed, compliance with the risk-based criteria must be demonstrated with appropriate dispersion modelling results. (Note that reduced flaring or incineration rates do not result in a proportional reduction in predicted concentrations.)

5) Ambient air monitoring (mobile and/or stationary) must be located where exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* are predicted.

   a) Ambient air monitoring in conjunction with appropriate flaring/incineration management procedures will only be accepted when it can be demonstrated that monitors can be placed in a manner that is reasonably protective of all locations where exceedances of the risk-based criteria are predicted. Stationary monitors are currently accepted to cover an arc of 22.5°C centred on the source. The licensee or operator must provide an NTS map of the area (1:50 000) indicating the locations of the stationary monitors and a table with the coordinates (i.e., Universal Transverse Mercator [UTM]). In cases where monitoring is proposed, a licensee or operator must demonstrate that there is good access to all areas with predicted exceedances *before* a request is submitted.

   b) The *Alberta Ambient Air Quality Objectives and Guidelines* must not be exceeded, based on a one-hour average. To accomplish this, ambient air monitoring must occur at intervals of 15 minutes or less. **If the 30-minute average exceeds the *Alberta Ambient Air Quality Objectives and Guidelines,* the flaring or incineration operation must be immediately shut in.**

6) If there is more than one meteorological condition that requires a management response, or if a combination of meteorological restrictions and ambient air monitoring is proposed, the management plan must be summarized in a flowchart that is clear and concise and can be applied by on-site staff during flaring or incinerating operations. Furthermore, if multiple flow rates are proposed in the management plan, the risk-based criteria must be met for each flow rate.

   a) The management plan must clearly specify the frequency at which the meteorological or ambient air quality monitoring data will be monitored by on-site staff. An averaging time of no more than 15 minutes is mandatory, as this allows for observations of trends and provides enough time to respond to elevated concentrations.

7) The management plan must clearly define under what conditions flaring or incineration may resume if suspended or may return to normal operations if a management option such as fuel gas is proposed. Flaring or incineration must remain suspended for at least one hour before operations may resume in order to prevent an exceedance or to respond to an exceedance.

   a) Flaring or incineration may begin again after one hour or after meteorological conditions change and remain favourable for 30 minutes, whichever is longer.

8) Real-time dispersion modelling flare management plans must be based on maximum predicted concentrations. Pseudo input parameters must be calculated using AERflare. If real-time dispersion modelling goes down, the operator must revert to a conventional flare management plan or shut in.

Appendix 8 Screening Dispersion Modelling Using AER Spreadsheet

The AER sour well test flaring and incineration permit spreadsheets and technical descriptions are available on the AER website www.aer.ca under Regulating Development > Rules & Directives > Directives > Directive 060. They provide a screening analysis of the SO_2 and H_2S dispersion from permanent and temporary flares and incinerators. If the screening level maximum concentration predictions in parallel and complex airflow terrain for a source meet the *Alberta Ambient Air Quality Objectives and Guidelines* (*AAAQO*), no further analysis is required. The spreadsheet can be submitted in support of the dispersion modelling assessment.

Maximum predictions for routine sources must meet the *AAAQO*. Due to the short-term nature of temporary nonroutine sources, risk-based criteria can be applied. The risk-based criteria apply to well tests and other temporary nonroutine flaring and incineration events. For further information about the spreadsheet refer to the AER flare User Guide: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities.

If it is not practical to modify flare or incinerator design parameters, you may consider evaluating the proposed design with more refined dispersion modelling approaches. Additional refined dispersion modelling is required if the screening level maximum concentration predictions in parallel and complex airflow terrain for a source do not meet the *AAAQO*. A refined dispersion modelling assessment must meet AEP's *Air Quality Model Guideline* (2013) or *Non-Routine Flaring Management: Modelling Guidance* (2013).

For routine flaring, a refined dispersion modelling assessment is also required if there are continuous SO_2 emission sources within 10 km of the location or within the isopleth of one-third of the *AAAQO* for SO_2 (as described in section 7.12.3), whichever distance is less. This requires that the cumulative effects of the proposed flaring or incineration be assessed in combination with other sources.

A licensee, operator, or approval holder is responsible for ensuring that appropriately trained and qualified personnel complete the air quality evaluations.

A refined dispersion modelling assessment must include the following:

1) A description of the meteorological data source (location, years, and months). For models that require meteorological data, five years of meteorological data from a standard period is recommended. Three months per year must be modelled from the data set centred about the month of the requested permit date. The acceptable data sets are posted on the AEP website at http://aep.alberta.ca/air/modelling/meteorological-data-for-dispersion-models.aspx. Additional information about modelling and meteorological data requirements is on the AEP website.
2) A wind rose (a representation of the history of wind directions and wind speeds).

3) Refined modelling source parameters for maximum flow rate (Qmax), average flow rate (Qavg), and one-eighth maximum flow rate (Q/8) from the spreadsheet.

4) A summary of the model input parameters (a printed copy of the input file is preferred, as output files may be large and need not be submitted).

5) The maximum predicted one-hour ambient air SO_2 concentration for maximum flow rate (Qmax), average flow rate (Qavg), and one-eighth maximum flow rate (Q/8).

6) If exceedances of the one-hour *AAAQO* for SO_2 are predicted, a histogram of the overall probability of exceedance based on meteorological data is to be calculated, as follows, by dividing the number of hours with predicted exceedances by the total number of hours used in the meteorological data set:

$$\text{Probability of exceedance} = \frac{\text{(Cumulative number of hours with predicted exceedances)}}{\text{(Total hours modelled)}}$$

7) An interpretation of the modelling results (output files or model result printouts may be included if not excessively large).

8) Histograms showing exceedances based on criteria (e.g., wind direction, wind speed, and stability class).

If the risk-based criteria are not met, a management plan (see appendix 7) must be developed to achieve the risk-based criteria. Requests with management plans must include enough information so that the AER can assess the management plan, including

1) for each flow rate, a summary table of output, including

   - meteorological conditions (stability class and range of wind speeds and directions) or times of day that result in predicted exceedance of the one-hour *AAAQO* for SO_2,
   - maximum predicted SO_2 concentration for each condition where exceedances are predicted, and
   - the expected overall probability of exceedances before and after implementation of the management plan;

2) for each flow rate, an area map showing

   - locations of predicted SO_2 ground-level concentration isopleths (with a minimum 10 km radius) in excess of the one-hour *AAAQO* for SO_2,
   - sectors with flaring restrictions (if proposed),
   - locations accessible with a mobile monitoring unit (if proposed),
   - approximate location of proposed stationary monitors (if proposed) and, if available, a recent air photo showing the approximate location of proposed stationary monitors, as well

as specifications of the monitor location in a format usable by the monitoring licensee, operator, or approval holder (e.g., UTM coordinates or latitude and longitude), with an acceptable offset distance if this is required to improve access or telemetry line of site; site reconnaissance must be conducted before submission to ensure that monitors can be placed, and

- UTM coordinates of stationary monitors, as well as distance and direction from well;

3) a calculation of makeup gas requirements as a percentage of the produced gas being combusted (gas may be used to increase plume rise; care should be taken to minimize gas waste); and

4) electronic copies (i.e., Microsoft Word or Excel files) of the management plan and decision tree (if applicable).

The AERflare.xls and AERincin.xls spreadsheets also evaluate minimum and maximum exit velocities with respect to downwash criteria. The results will help the licensee, operator, or approval holder optimize flare and incinerator design and verify parameters used for temporary flaring and incineration permit requests.

1) If downwash is predicted, the spreadsheet source parameters will conservatively account for downwash; however, it is recommended that the stack design parameters (e.g., stack diameter) be modified to avoid downwash.

2) The spreadsheet provides maximum and minimum exit diameters based on the recommended exit velocities. You must size the exit diameter within the range of exit diameters provided in AERflare.xls. Exit diameter is a permitted parameter. A qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*[24] must review the design parameters.

The licensee, operator, or approval holder may submit data based on modified modelling methods for consideration; however, results from one of the accepted unmodified models must also be submitted for comparison. Description and scientific justification of the modifications must be provided. Generally, review of permit requests that use a modified modelling method requires more time, and the AER may accept or reject the modified results at its discretion.

[24] *Engineering and Geoscience Professions Act* RSA 2000 c. E-11, as amended.

Appendix 9 Resident Flaring/Venting/Incinerating Notification Sample Form

We will be flaring/incinerating/venting a (___ % H_2S) well in accordance with AER *Directive 060* at the location stated below.

Flaring/Incinerating/Venting Category (check those that apply)	**AER Office (check one)**
Well test flaring	Bonnyville (780-826-5352)
Well test venting	Drayton Valley (780-542-5182)
Well test incinerating	Grande Prairie (780-538-5138)
	Fort McMurray (780-743-7214)
(Check one)	High Level (780-926-5399)
Oil well	Medicine Hat (403-527-3385)
Gas well	Midnapore (403-297-8303)
	Red Deer (403-340-5454)
	Slave Lake (780-843-2050
	Edmonton – formerly St. Albert (780-460-3800)
	Wainwright (780-842-7570)

Flaring/Venting/Incinerating Comments	
Well Licence No.	
Well Name	
Location of Well (LSD)	
Estimated Flare/Incinerate/Vent Timing (30-day window)*	
Estimated Start Date	
Estimated End Date	
Flaring/Incinerating/Venting Duration	
Estimated Volume (10^3 m^3/day)	
Licensee or Operator Name	
Licensee or Operator Representative	
Contact Phone Number	
Testing Contractor	
Testing Representatives on Site	
Daytime Cell Phone Number	
Nighttime Cell Phone Number	
Emergency Phone Number	

Please phone (____) ____ - ______ if you would like notification 24 or 48 hours in advance of flaring/ incinerating/venting operations.

- 30-day window is to accommodate for weather and operational delays.
- Renotification is mandatory after 90 days.

Note:____

____

If you have questions or concerns, please phone (___) ___ - ______

Appendix 10 Agreement on Zero Flaring and Venting Agreement

The following serves to outline the agreement between __________________________ (applicant) and __________________________ (landowner or occupant) respecting flaring at the well located at ______________________W___. The applicant agrees to not flare from the well before putting the well on production except as stated below in this agreement or in an emergency. Venting is not to be used as an alternative to flaring.

Exceptions

Flaring may occur as indicated below and is limited to at most two of the activities:

- Well testing Yes? ____ No?_____
- Well cleanup Yes? ____ No?_____
- Drillstem testing Yes? ____ No?_____

Emergencies

The licensee, operator, or approval holder may flare in emergency situations for safety of the public or environmental protection.

If the ownership of the well is transferred to another licensee, operator, and/or approval holder, this agreement will remain in effect for the new licensee, operator, or approval holder and it is the licensee, operator, or approval holder's responsibility to advise any successors of this agreement.

This agreement no longer applies once this well is tied into a production facility or once production operations begin.

Applicant Signature________________________ Landowner or Occupant Signature (optional)__________________________

Printed Name _____________________________ Printed Name______________________________

Licensee, operator, or approval holder ____

Location__________________________________

Telephone________________________________ Telephone_________________________________

Email/Fax________________________________ Email/Fax_________________________________

Date ____________________________

Appendix 11 Request to Extinguish Sour Gas Flare Pilots

The following minimum requirements must be met in any situation where it is proposed to extinguish a flare pilot at a sour facility:

1) The maximum stabilized wellhead pressure must be determined based on the measured stabilized static wellhead pressure corrected for the hydrostatic head of any liquid present in the wellbore at the time of testing.

   a) This correction for the liquid column hydrostatic head must use the density of the produced water for the entire fluid column present in the wellbore.

   b) The maximum stabilized static wellhead pressure must be determined by a qualified well test professional using accepted engineering practices. AER *Directive 040* provides regulations for conducting pressure tests on wells.

2) The following features must be incorporated into the facility for consideration of the request to extinguish the flare pilot:

   a) Nonfragmenting rupture disks must be installed on the upstream side of all pressure safety valves (PSVs). This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association.

      - A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding PSV to allow detection of leakage or a disk rupture.

   b) Two block valves in series must be installed for manual depressurizing valves connected to the flare.

   c) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves (ESDVs), and a control system configured to isolate the battery from the well and outlet gas pipeline. There must be no automatically controlled emergency depressurizing valves connected to the flare.

3) Upstream piping to the well must be designed for the maximum pressure that might be encountered. The *minimum* operating requirements for any facility approved for extinguishing flare pilots include the following:

   a) The licensee, operator, or approval holder must monitor and document on a weekly basis the pressure between rupture disks and PSVs.

   b) If a rupture disk fails or if odours result from gas released to the flare stack, the flare stack must be lit and immediate notification must be given to the appropriate AER field centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the licensee, operator, or approval holder demonstrates to the satisfaction of the appropriate AER field centre that related problems have been successfully corrected.

c) The sweet gas or propane pilot must be ignited prior to any flaring or depressurizing at the site.

d) The operation of the emergency shutdown system, including ESDVs, must be verified and documented at least once a year.

e) AER approval to extinguish the flare pilot must be visibly displayed at each site.

4) Residents within the emergency planning zone (EPZ) must be notified of plans to extinguish the flare pilot.

5) The following information must accompany the licensee's, operator's, or approval holder's request to extinguish flare pilots:

a) a list of all wells connected to the battery, including

i) normal wellhead operating pressure, and

ii) maximum stabilized static wellhead pressure;

b) the maximum design operating pressure of the piping and pressure vessel systems for the battery, including

i) a list of all PSVs connected to the flare and related release set-pressures, and

ii) a list of related rupture disks and burst pressures;

c) written confirmation that

i) none of the wells connected to the facility are completed in pools that have active injection or cycling schemes,

ii) rupture disks on PSVs and two valves in series have been installed on all streams tied into the flare system,

iii) maximum H_2S release rates will not exceed the level-1 or -2 sour well classification,

iv) residents within the EPZ have been notified, and

v) high-pressure shutdowns are in place, with a statement confirming calibration frequency.

Appendix 12 Mandatory Elements of a Fugitive Emissions Management Program

The following elements are to be included in the FEMP:

1) Contact information of the individual accountable for the FEMP.
2) Resources allocated to developing and implementing the FEMP. Include which group within the company is responsible for maintaining and updating the FEMP and who (e.g., corporate environmental or operations group, third party) will be conducting the surveys and screenings.
3) Preventive maintenance practices to reduce or prevent fugitive emissions.
4) The procedures and plans that will be used to meet the required frequency of fugitive emissions surveys and screenings and to complete repairs. Indicate any deviations from the prescribed frequency and provide justification.
5) Techniques and equipment used for fugitive emissions surveys and screenings. Include equipment make and model and any plans to use alternative technologies.
6) Calibration methods and equipment maintenance practices for equipment used for fugitive emissions surveys.
7) Training programs and certification completed by individuals conducting fugitive emissions surveys or screenings.
8) Description of how individuals will be trained and how often they will be retrained or recertified.
9) Internal procedures to track, manage, and verify the status of repairs.
10) Data management practices and systems to ensure that survey and screening results trigger required repairs and that the repairs are captured for annual reporting.
11) Provisions for continuous improvement of the FEMP, including how FEMP data will be used to evaluate program performance.

Appendix 13 Fugitive Emissions Record Keeping

Fugitive Emissions Survey or Screening Record
Directive 060

The information in this report may be made available to the public.

Duty Holder Information
Licensee:
Operator (if different from licensee):
Name and contact information of party conducting the survey:
Survey or Screening Information
Fill in all that is applicable.
Reporting facility ID:
Facility licence number:
Site name:
Site type (well type or energy development code if applicable):
Site service: ☐ Sweet (<0.01 mol/kmol H_2S) ☐ Sour (≥0.01 mol/kmol H_2S)
Legal land description (00-00-000-00W0 DLS format):
Type: ☐ Survey – site ☐ Survey – only storage tanks with vent gas controlled ☐ Screening
Survey or screening date (yyyy-mm-dd):
Type of equipment or method used (e.g., gas-imaging camera, Method 21, AVO):
Do any of the following exist:
☐ Thief hatch not closed Total number: ____________
☐ Pneumatic device emitting vent gas or operating in excess of normal operating conditions Total number: ____________
☐ Control device, flare, combustor, etc. not operating Total number: ____________
For the sources of fugitive emissions identified above, justify their occurrence or list planned mitigation actions:

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Information on Sites with Fugitive Emissions						
Fugitive emissions ID[1]	**Component or equipment type**	**Emissions rate (if applicable)**	**Repair date (if applicable)**	**Repair integrity confirmed within 7 days (check if yes)**	**Method of confirming repair integrity**	**Additional comments (repair delay, further evaluation req'd, etc.)**

[1] Unique ID assigned by the duty holder to track the source of fugitive emissions corresponding to tag if applicable.

U.S. Energy Information Administration

OCD Exhibit 20

NATURAL GAS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY › | FAQS ›

Natural Gas Gross Withdrawals and Production

(Volumes in Million Cubic Feet)

Data Series: Vented and Flared

Period-Unit: Annual-Million Cubic Feet

Show Data By: ◯ Data Series ◉ Area	Graph Clear	2013	2014	2015	2016	2017	2018	View History
U.S.		260,394	293,916	289,545	230,410	281,947	468,347	1936-2018
Alaska		7,219	6,554	5,385	8,541	7,605	8,210	1967-2018
Alaska Onshore		5,670	5,779	4,755	7,557	6,739	7,229	1992-2018
Alaska State Offshore		1,549	776	630	984	866	981	1992-2018
Arkansas		0	NA	0	NA	0	0	1967-2018
California		0	NA	0	NA	0	0	1967-2018
California Onshore		NA	NA	NA	NA	NA	NA	1992-2018
California State Offshore		NA	NA	NA	NA	0	0	2003-2018
Federal Offshore California			NA	NA		NA	0	2003-2018
Colorado		0	NA	0	2,620	4,279	5,097	1967-2018
Federal Offshore Gulf of Mexico		14,619	16,575	10,858	15,067	13,733	13,839	1997-2018
Kansas		0	NA	0	NA	0	0	1967-2018
Louisiana		3,912	4,606	3,787	5,106	5,338	5,939	1967-2018
Louisiana Onshore		3,912	4,606	3,787	5,106	5,338	5,939	1992-2018
Louisiana State Offshore		NA	NA	NA	NA	0	0	1999-2018
Montana		0	NA	6,884	4,214	3,121	3,540	1967-2018
New Mexico		21,053	19,119	24,850	25,680	17,494	37,220	1967-2018
North Dakota		102,855	129,717	106,565	70,045	88,555	147,485	1967-2018
Ohio		0	0	0	0	0	0	1967-2018
Oklahoma		0	0	0	0	0	0	1967-2018
Pennsylvania		0	0	0	0	0	0	1967-2018
Texas		76,113	90,125	113,786	87,527	123,404	238,054	1967-2018
Texas Onshore		76,113	90,125	113,786	87,527	123,405	238,054	1992-2018
Texas State Offshore		0	NA	NA	NA	0	0	2003-2018
Utah		0	NA	0	NA	0	0	1967-2018
West Virginia		0	NA	0	NA	0	0	2006-2018
Wyoming		34,622	27,220	3,473	11,610	18,417	8,958	1967-2018
Other States								
Other States Total		0	0	13,957	0	0	6	1991-2018
Alabama		0	NA	0	NA	0	0	1967-2018
Alabama Onshore		NA	NA	NA	NA	NA	NA	1992-2018
Alabama State Offshore		NA	NA	NA	NA	NA	NA	1992-2018
Arizona		0	0	0	0	0	0	1971-2018
Florida		0	NA	0	NA	0	0	1971-2018
Idaho				0	0	0	6	2015-2018
Illinois		0	NA	0	NA	0	0	1967-2018
Indiana		0	0	0	0	0	0	2003-2018
								1967-2018

Kentucky		0	NA	0	NA	0	0	
Maryland		0	0	0	0	0	0	2006-2018
Michigan		0	NA	0	NA	0	0	1967-2018
Mississippi		0	NA	0	NA	0	0	1967-2018
Missouri		0	0	0	0	0	0	2007-2018
Nebraska		0	NA	0	NA	0	0	1967-2018
Nevada		0	0	0	0	0	0	1991-2018
New York		0	0	0	0	0	0	1967-2018
Oregon		0	0	0	0	0	0	1996-2018
South Dakota		0	NA	13,957	0	0	0	1967-2018
Tennessee		0	0	0	0	0	0	1967-2018
Virginia		0	NA	0	NA	0	0	1967-2018

Click on the source key icon to learn how to download series into Excel, or to embed a chart or map on your website.

- = No Data Reported; -- = Not Applicable; **NA** = Not Available; **W** = Withheld to avoid disclosure of individual company data.

Notes: Beginning with 2006, "Other States" volumes for the production series include the following states/areas: Alabama, Arizona, Florida, Idaho, Illinois, Indiana, Kentucky, Maryland, Michigan, Mississippi, Missouri, Nebraska, Nevada, New York, Oregon, South Dakota, Tennessee, and Virginia. Federal Offshore Pacific is included in California through 2017, and in "Other States" starting in 2018. Production series data for 2018 forward are estimates. Final 2018 state-level production series data will not be available until the 2018 Natural Gas Annual is published (scheduled for the third quarter of 2019). Gross withdrawal volumes in Florida fluctuate from year to year because nonhydrocarbon gases are occasionally included in gross withdrawals. See Definitions, Sources, and Notes link above for more information on this table.

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