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 CCR 404-1

Cause No. 1R Docket No. 200600115
800/900/1200 Mission Change Rulemaking

This statement sets forth the basis, specific statutory authority, and purpose for amendments ("800/900/1200 Mission Change") 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 November 2, 2020.

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 Professional 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;" 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).

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 § 34-60-106(2.5). 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 the 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 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 Professional 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 pooling application. *Id.* § 34-60-116(1)(b)(I)–(II). Finally, Senate Bill 19-181 add 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.

2. Professional Commission.

Another fundamental change enacted by Senate Bill 19-181 is a transition to a professional Commission. Currently, the Commission is a nine-member volunteer body that meets periodically. Senate Bill 19-181 made several structural changes to the Commission. First, it made the Commission a professional body by requiring that "[t]he appointed members of the Commission shall devote their entire time to the duties of their offices to the exclusion of any other employment and are entitled to receive compensation as designated by law." C.R.S. § 34-60-104.3(2)(b). Second, Senate Bill 19-181 reduced the number of Commissioners from nine to seven, and made the Executive Directors of CDPHE and the Department of Natural Resources *ex-officio*, non-voting members. *Id.* § 34-60-104.3(2)(a). Finally, Senate Bill 19-181 changed the qualifications and criteria for selecting Commission members, altered term limits, and prohibited Commissioners from serving with conflicts of interest. *Id.* § 34-60-104(2)(b)–(e).

The Professional Commission provisions of Senate Bill 19-181 became effective "on the earlier of July 1, 2020, or the date on which all rules required to be adopted by Section 34-60-106(2.5)(a), (11)(c), and (19) have become effective." *Id.* Because the 800/900/1200 Mission Change Rulemaking occurred after the Professional Commission was seated on July 1, 2020, the Commission revised several of its Rules to account for the transition to a Professional 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.

Senate Bill 19-181 amended the definition of "minimize adverse impacts," a term used in both to describe the Commission's new mission, C.R.S. § 34-60-106(2.5), 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" does not include 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.

Senate Bill 19-181 also 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* § 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.

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 and other statutes:

- Section 25-8-202, C.R.S. (Implementing agencies must protect present and future beneficial uses of groundwater);
- Section 34-60-102, C.R.S. (Legislative declaration);
- Section 34-60-103, C.R.S. (Definitions);
- Section 34-60-104.5, C.R.S. (Duties of the Director);
- Section 34-60-105, C.R.S. (Powers and authority of the Commission);
- Section 34-60-106, C.R.S. (Specific powers and duties of the Commission);
- Section 34-60-107, C.R.S. (Prohibiting waste);
- Section 34-60-108, C.R.S. (Procedural rules);
- Section 34-60-110, C.R.S. (Subpoena power);
- Section 34-60-116, C.R.S. (Pooling);
- Section 34-60-117, C.R.S. (Protection of correlative rights);
- Section 34-60-118, C.R.S. (Unit operations);
- Section 34-60-119, C.R.S. (Production limitation)
- Section 34-60-120, C.R.S. (Authority over federal lands and minerals);
- Section 34-60-121, C.R.S. (Enforcement);

- Section 34-60-122, C.R.S. (Calculation of expenses)
- Section 34-60-124, C.R.S. (Oil and gas conservation and environmental response fund);
- Section 34-60-127, C.R.S. (Reasonable accommodation of surface owners)
- Section 34-60-128, C.R.S. (Habitat stewardship and consultation with Colorado Parks and Wildlife);
- Section 34-60-130, C.R.S. (Spill reporting); and
- Section 34-60-131, C.R.S. (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 Rulemaking. Based on this stakeholder input, 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 its sister agencies, Commission Staff met with staff from Colorado Parks and Wildlife, the Air Pollution Control Division, the Water Quality Control Division, and the Hazardous Materials and Waste Management Division. 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 each sister agency. The Commission's Staff also met with staff from federal regulatory agencies including the Bureau of Land Management and the Environmental Protection Agency.

On June 19, 2020, the Commission issued a draft of the proposed 800, 900, and 1200 Series Rules and this 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.

In the Notice, 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.

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, 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 Colorado Administrative Procedure Act, § 24-4-103(12.5), C.R.S.;
- 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, and 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 November 2, 2020—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 November 2, 2020, 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 to retrofit existing equipment.

100 Series Rules--Definitions

The Commission revised existing 100 Series definitions, or adopted new definitions, of the following terms:

Avoid Adverse Impacts

Commencement of Production Operations

Commercial Disposal Well

Compensatory Mitigation

Completed Well

Cuttings Trench

Flaring

Flowback

Fluid

High Priority Habitat

Investigation-Derived Waste

Land Application

Land Treatment

Minimize Adverse Impacts

Mitigate Adverse Impacts

Mitigation

Oily Waste

Pollution

Production Evaluation

Productivity Test

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 (including both disposal and enhanced recovery 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. 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 31s and 33s relative to the submission of processing of related Oil and Gas Development Plans.

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 wells any foreign substance into an underground source of drinking water without the Commission's approval.

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, 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.

Rule 801.a

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), 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 Underground Injection Control (UIC) wells are used to inject fluids brought to the surface during oil and gas production and to conduct stimulation 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. 40 Fed. Reg. 13,040, 13,040–41 (Apr. 2, 1984); *see also* 40 C.F.R. § 147.300.[1]

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 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 application

[1] 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* 40 Fed. Reg. at 13,041; *see also* 40 C.F.R. § 147.301(a).

involving surface disturbance must comply with the Commission's 300 Series Rules governing permits for surface disturbing activities, including obtaining approval of Oil and Gas Development Plan 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"), Commission adopted a new Rule 802.b, clarifying that injection wells will not be authorized if the well would violate an applicable numeric or narrative domestic or agricultural groundwater quality standard or classification in WQCD Regulations 41, 41.5 or 42.

Rule 801.c

The Commission adopted a new Rule 801.c, specifying a standard that injection wells 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 formation. 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 formations, 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.

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 802.

The Commission moved prior Rule 324B to Rule 802.

Rule 802.a

In Rule 802.a, the Commission revised both its procedural and substantive standards for UIC Aquifer Exemptions. Procedurally, the Commission specified that notice of an UIC Aquifer Exemption application must be provided to both EPA and the WQCD. The Commission specified that coordination with the WQCD and EPA 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.

Substantively, the Commission 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 a maximum depth limit and salinity level for water that could be used for drinking water or agricultural purposes from prior Rule 324B. Instead, the Commission required an applicant to demonstrate that a proposed UIC Exemption 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. 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 COGCC 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.b

In Rule 802.b, 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.

Rule 802.c

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.c. 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.

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 application requirements for Class II Underground Injection Control (UIC) wells. Rule 803 applies to all categories of disposal wells. Additionally, as discussed in Rule 810, enhanced recovery wells must also comply with Rule 803, unless otherwise specified.

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

Rule 803.b

In Rule 803.b, the Commission required injection well applications to comply with the 300 Series permitting requirements. These permitting requirements include the submission of an Oil and Gas Development Plan pursuant to Rule 303 for development of any new well pad, a Form 2A pursuant to Rule 304 for any surface disturbance that does not require a full Oil and Gas Development Plan, such as modification of an existing well pad, and a Form 2 pursuant to Rule 308 for drilling a new injection well or modifying an existing injection well. Operators need only submit a Form 2A for any surface disturbance that meets the requirements of Rule 304.a. This 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 disposal well that the operator proposed to drill. As part of moving towards a single, consolidated permitting process, the Commission intends for all permit applications to follow similar procedures. 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.

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 injection projects, which are governed by Rule 810. 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 31 and Form 33, 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). 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, 41.5, 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.

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, as defined in the Commission's 100 Series Rules. 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. The Commission also specified standards for seismic monitoring, and for operators to submit requests to increase injection well radii from 1/4 mile to 1/2 mile to the Director via a Form 4, Sundry Notice, which codifies the Commission's prior practice. In Rule 803.f.(1).D, 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.

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.

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 list of persons who must obtain 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, an injection well applicant is only required to provide notice to surface and mineral owners within 1/4 mile of a proposed Class II injection well. *See* Prior Rule 325.i; 40 C.F.R. § 144.31(e)(9). However, although a Class II injection 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. 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. The Commission also clarified that surface use agreements are necessary for every surface property owner overlying the injection zone, if the injection zone is beneath or crosses into a property of a different surface owner than the surface estate where the injection well is located on the surface. In the event a directional disposal well was drilled beneath the property of a surface owner who had not signed a surface use agreement with the disposal well operator, it could potentially interfere with the surface owner's right to drill a vertical disposal well into the pore space beneath her own property. Finally, in Rules 803.g.(3).A. B, and C, the Commission provided substantive standards for what the Surface Use Agreements must allow, which include authorization to use pore space within a 1/4 mile buffer of the surface hole location and completed interval, and 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, Sundry Notice pursuant to Rule

803.f.(1).C 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 operators have secured property rights to access pore space. Unlike oil and gas formations, pore space is subject to a distinct property rights regime. Accordingly, the Commission also clarified in Rule 803.g.(3) that surface use agreements must specifically allow for the use of pore space within the injection zone. The Commission received robust stakeholder feedback about Rule 803.g.(3) in its February and May Straw Dog drafts of the 800 Series. The Commission solicits additional stakeholder feedback about Rule 803.g.(3) in party prehearing statements to allow the Commission to continue evaluating the proposed rule.

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).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 Rule 909.j.(1)–(4), including the list of analytes in Rule 909.j.(1). In Rule 803.g.(5).D, the Commission further clarified that operators must evaluate disposal 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.

Consistent with the revisions to Rule 803.g.(5), the Commission adopted a new definition of the term Fluids in its 100 Series Definitions, 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 that will provide the Director with information necessary to ensure that injection well applications comply with the standards in Rules 801.c and 801.d. 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.[2] 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 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.[3]

Accordingly, the Commission determined that a robust seismicity evaluation is necessary for all proposed injection wells. 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 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. The generally accepted perspective is that an induced event from underground injection can occur within ten kilometers (6.2 miles) of an injection. However, some evidence in the administrative record suggests that the distance may be greater. Accordingly, the Commission views the 6.2 mile radius as distance in which there is a higher probability of induced seismicity. With that perspective in mind, 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. The Commission determined that approximately doubling the review distance provides an adequate margin of safety.

Under 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

[2] *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).

[3] *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).

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 U.S. Geological Survey's ("USGS") Earthquake Catalog. *See* USGS, *Earthquake Catalog*, https://earthquake.usgs.gov/earthquakes/search/ (last visited May 20, 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.

Under 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, and 1200 Series 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.(C) to reference the two probability metrics used in the USGS Seismic Hazard Map database. Accordingly, the Commission 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 May 20, 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 injection 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 injection 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.

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 domestic and irrigation 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 Oil 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 Oil 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 Oil Recovery projects. However, remedial corrective action plans are not required for enhanced oil recovery projects where the offset well is a producing well that is part of the project.

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 the Rules 806 and 905.c.(2).D.i, Operators must track both the source of and ultimate disposal location of all injected produced water by submitting a Form 26.

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 providing notice of injection well applications to mineral owners, surface owners, and local governments. The notice provisions of Rule 803.g.(14).A, B, and C are different than the notice required under the 300 Series Rules pursuant to Rule 803.b in several ways. First, Rule 308 does not include public notice requirements for Form 2 applications. Thus, for any Form 31 application that involves only drilling a new disposal well or modifying an existing well without any associated new surface disturbance, notice to nearby mineral and surface owners would not otherwise be required by Rule 803.b. Accordingly, the Commission required such notice for injection wells through Rule 803.g.(14). Second, Rule 303.e.(1) requires operators to provide notice of OGDPs (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.(2), the Commission determined that mineral and surface owners within 1/2 mile of a disposal 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 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. In both Rules 803.g.(15) and 803.k, rather than providing separate hearing request procedures for disposal injection applications, the Commission instead cross-referenced the standard hearing request procedures in Rule 507.a.

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), 325.d.(1) & (3) governing injection zone water quality analysis and geophysical (resistivity) 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 Rule 909.j.(1)–(4). For the geophysical log requirement of Rule 803.h.(2), 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. A suite of open-hole gamma ray, electrical resistivity, and density-porosity logs or equivalent cased-hole logs yielding similar results are acceptable. The Commission also added two new components for a Form 31 Subsequent: the results of any step rates or injectivity tests, and hydrocarbon productivity evaluations. 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, Injection Well Permit Applications – Intent. Form 33 Intents must provide all information pertinent to the Commission 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.

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, Injection Well Permit Applications – Subsequent. A Form 33 Subsequent must be submitted after an injection well is drilled to verify that the wellbore maintained integrity during the drilling process, passes 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.(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.

Rule 803.k

The Commission moved prior Rule 325.m to Rule 803.k, 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. And the

Commission added new Rules 803.k.(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, 41.5, and 42.

Rule 803.l

The Commission moved prior Rule 325.n to Rule 803.l. Consistent with transitioning into a single, consolidated application process for all forms of injection wells, the Commission expanded the scope of the public notice requirements to apply to all injection well applications, rather than only applications for dedicated injection wells. Consistent with Senate Bill 19-181's changes to the Commission's statutory authority, *see* C.R.S. § 34-60-106(2.5), the Commission revised the standard for a public comment to trigger a Commission hearing to cross-reference Rule 803.k. The Commission also provided that injection well public notice will be published on the Commission's website, rather than only in a newspaper.

Rule 803.m

The Commission moved prior Rule 325.o to Rule 803.m. The Commission changed the start date for when information necessary to process a Form 31 or Form 33 application must be received from the date of receipt, which was a confusing term, to the date of approval of the application Intent. This will provide additional clarity to operators about when they must submit a complete Form 31 or Form 33 application. 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, and because EPA does not prescribe a maximum timeframe for agencies with delegated authority to process Class II well permit applications.

Rules 803.n and 803.o

The Commission moved prior Rule 405, governing notice of commencement and discontinuance of injection operations, to Rules 803.n and 803.o. In Rule 803.n, consistent with the Commission's Form 5A requirements, the Commission clarified that operators must immediately provide notice of the commencement of injection on a Form 5A, Completed Interval Report. In Rule 803.o, the Commission clarified that operators must provide notice of discontinuance of injection operations on a Form 4, Sundry Notice.

Rule 804.

The Commission moved prior Rule 324C to Rule 804. 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 804.a

In Rule 804.a, the Commission clarified that Rule 804'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 804.b

In Rule 804.b, the Commission specified that all injection fluid analyses must include at least total dissolved solids, major anions, and major cations. 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 804.c

In Rule 804.c, the Commission added a requirement that Commission 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 804.d

In Rule 804.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 805.

The Commission added a new Rule 805 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 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. 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. 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 Rule 909.j.(1)–(4). Among other things, Rule 909.j requires submission of electronic sampling data on a Form 43.

Rule 806.

The Commission adopted a new Rule 806, 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 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 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 807.

The Commission moved prior Rule 316A to Rule 807. The Commission revised the title of Form 14A, Non-Produced Class II Exploration and Production Waste Injection, to provide better clarity about what information is reported on a Form 14A. The Commission similarly revised the title of Form 14, Monthly Report of Non-Produced Class II Exploration and Production Waste Injected, for the same reason. The Commission revised the wording of Rules 807.a and 807.b to clarify that the non-produced fluids that are disposed in injection wells are classified as Exploration and Production Waste. The Commission also clarified in Rule 807.a.(2) that operators must obtain the Director's approval of a Form 14A for any new disposal facility or for changes in the source of non-produced Class II waste.

Rule 808.

The Commission moved prior Rule 325.d.(7) to Rule 808. The Commission clarified that simultaneous injection well applications must satisfy the same requirements as other injection well applications under Rules 803, 804, 805, 806, and 807.

Rule 809.

The Commission moved prior Rule 325.f to Rule 809. The Commission clarified that commercial disposal well applications must satisfy the same requirements as other injection well applications under Rules 803, 804, 805, 806, and 807, in addition to satisfying the financial assurance requirements of Rules 706, 707, and 712.

The Commission also adopted a new requirement in Rule 809.b that Commercial Disposal Well Facilities 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 809, 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 810.

The Commission moved prior Rule 401, governing enhanced recovery wells, to Rule 810. The Commission moved the components of prior Rule 401 that regulated gas storage to Rule 220.d. Accordingly, the Commission removed references to storage operations from Rule 810.a

Rule 810.a

In Rule 810.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.[4]

Rule 810.b

In Rule 810.b, the Commission expanded and revised prior Rule 401.b's requirements for enhanced recovery injection 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, and 807, 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.(10). 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 810.b.(4), (6), & (8)–(11).

Many of Rule 810.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 810.b.(4), 810.b.(6), 810.b.(8), 810.b.(9), 810.b.(10), and 810.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. As with Rule 803.g.(8), Operators may obtain water well permit and construction information required by Rule 810.b.(10) from the Colorado Division of Water Resources.

Rule 810.c

The Commission moved prior Rule 402 to Rule 810.c. The Commission clarified the language of Rule 810.c to explain that the Commission will issue a notice of hearing at the time an enhanced recovery injection 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.

[4] *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.

Rule 810.d

The Commission moved prior Rule 405.c and 405.d to Rule 810.d.(1) and (2). The Commission did not substantively revise prior Rule 405.c. However, in Rule 810.d.(2), the Commission revised prior Rule 405.d to provide additional clarity, and to specifically cross-reference the well plugging requirements of Rule 434.

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 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 odor 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 exploration and production 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 exploration and 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 Exploration and Production Waste ("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 Director and 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 Water Quality Control Commission ("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), 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), 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.

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), 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)

Additionally, 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. Accordingly, in Rule 901.a.(2), the Commission clarified that if the Director requires an operator to take any of these actions, 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 211.c, which similarly provides procedures for operators to appeal Rule 901.a.(3) 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, and must be heard at the Commission's next regularly scheduled meeting. Because Senate Bill 19-181 provides for full-time Professional 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. 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.

Some stakeholders suggested that the transition to the Professional 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 five individual Commissioners, Commission 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 professional 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. 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). 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* § 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 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), (10). Because the Act expressly contemplates that the Commission will delegate implementation powers to the Director, C.R.S. § 34-60-106(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 specifying the "reasonable cause" standard of proof, limiting the situations where the Director can require an operator to take action to situations where the operator has taken an action that "impacts or threatens to impact public health, safety, welfare, the environment, or wildlife resources," and 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 addressing situations where an operator's actions "impacts or threatens 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 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 court 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 mitigate immediate threats to public health, safety, welfare, the environment, and wildlife resources, C.R.S. § 34-60-106(2.5), than existed in 1997, when the Commission adopted prior Rule 901.c (which was Rule 901.e at the time it was adopted).

Rule 901.b

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 Administrative Procedure Act ("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)(a). 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.,* Rules 408.e, 429.a, 429.e, 430, 602.g.(2), 603.c.(3), (9), 603.k, 603.o.(6), 608.a, 608.d, 609.b, 610.b, 610.i, 610.k, 610.q, 612.b.(1), 612.d.(2), 612.e, 1102.b, 1102.d.(2), (3), 1102.g.(2), 1102.l.(2), 1104.h.(1).B, 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 21 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 rules." 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, Professional 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, and 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).

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 added 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 by the Commission's Rules or applicable regulations promulgated by another federal, state, or local agency." This added clause refines the definition to exclude contamination and degradation of air, water, soil, and biological resources that is expressly authorized by the Commission or another regulatory agency. The Commission intentionally used the term "authorized" rather than "allowed" to delineate authorized pollution from "allowed" pollution. The term "authorized" pollution is intended to address, for example, release of an air pollutant from a facility with an air pollution permit at a level below the emissions limit set in the facility's permit for that pollutant. By contrast, "allowed" pollution might be misinterpreted as emission of a pollutant that simply is not addressed by an agency's rules or a permit at all.

Consistent with this revision to the 100 Series definition of "Pollution," the Commission required in Rule 901.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 such 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, § 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). 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* § 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 controllers, 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, but did not substantively revise the Rule. 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. The Commission also revised the clause "shall constitute a violation of water quality standards" to instead say "violates 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. Although the Commission did not make substantive changes to Rule 902.d, numerous stakeholders raised questions about it. 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 911 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. 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 materials." 6 C.C.R. § 1007-2:1–1.2.

Rule 903.

The Commission consolidated portions of prior Rules 317.p, 604.c.(2).C, 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 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 and 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 gas, and fires caused by improper flaring of 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 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 show that HAPs emitted by the oil and gas sector, including but not limited to benzene, toluene, ethyl benzene, xylenes, 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 ozone formation. *See* 40 C.F.R. § 51.100(s). Evidence in the Administrative Records 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 ("NAAQS") 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. Finally, the primary constituent of natural gas is methane, which contributes to climate change because it is a greenhouse gas that is 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. Additionally, 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 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 protection 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 both oil and gas." C.R.S. § 34-60-103(11)(a). Thus, for wells that produce only gas, any escape or release of gas into the air—in other words, venting—constitutes waste, and for wells that produce both oil and gas, any excessive or unreasonable venting constitutes waste. The Act further provides that for both oil and 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. 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: gas that is lost into the air at the surface. Surface destruction is an express reference to flaring: 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 determines 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 prevent 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 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," and prior Rule 323 prohibited open pit storage of oil and other hydrocarbon substances because it "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 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 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 inconsistencies."). 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 Air Pollution Control Division ("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 differences from 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. 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 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.

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 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 LGDs 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 both Rules 903.a.(1) and (2), 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.

Rule 903.a.(2)

In Rule 903.a.(2), when unplanned flaring occurs, the Commission clarified that notice must be provided immediately 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 emergency calls related to flaring events. Allowing two hours for operators to provide notice of unplanned events, rather than requiring immediate notice would obviate many of the safety 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. 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 2000 feet, it is important for proximate local governments to be notified when flaring occurs so that they can facilitate the appropriate emergency response actions. The Commission also added venting to the list of activities that require notice under Rules 903.a.(1) and (2). Because venting may have public health and safety impacts, it is important for local governments and emergency response agencies to also be informed of planned and unplanned venting events. 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)

Finally, 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).

In its 100 Series Rules, the Commission defined two terms used in Rule 903.a: Venting and Flaring. 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 intentionally used the term "natural gas" in the definition of flaring to clarify that the definition of flaring does not apply to hydrocarbons that evaporate or vaporize from liquid hydrocarbons, including flash gas. Additionally, the Commission excluded two categories of combustion from its definition of flaring. One exclusion is gas that is intentionally used for a beneficial onsite process. These beneficial onsite processes would not clearly meet the definition of waste. Additionally, there are fewer safety impacts from controlled combustion in an onsite process than there are from flares. The second exclusion is for combustion that is required by the AQCC for purposes of emissions control. The AQCC has adopted numerous emissions control regulations requiring the use of emission control devices to reduce VOC and methane emissions, especially from storage tanks. The Commission does not intend for combustion that is specifically required by the AQCC to fall within its definition of flaring.

The Commission also defined Venting in its 100 Series Rules as "intentionally allowing natural gas to escape into the atmosphere." The Commission chose to use the verb escape for consistency with the statutory definition of waste, C.R.S. § 34-60-103(11)(a). The Commission also used the word "intentionally" to differentiate between unintentional leaks and intentional venting. The Commission intends for its definition of venting to address affirmative actions by operators to open valves, or otherwise take an action that allows natural gas to escape into the air. The AQCC has a distinct set of regulations requiring operators to identify and repair unintentional leaks. Because of the protectiveness of the AQCC's leak detection and repair regulations, the Commission determined that it was unnecessary for its Rules to address leak detection and repair, and sought to avoid confusion that could be engendered from both agencies regulating the same activity. In the initial Straw Dog version of Rule 903 that the Commission's staff released for stakeholder review in February 2020, staff included a draft rule that required operators to submit leak detection and repair 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.(7) 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 gas to escape into the air as part of a process, such as pneumatic devices and compressors. Because the escape of natural gas from such a device is not "intentional"—that is, no person must take an affirmative action to cause the release to occur, but rather it occurs automatically—emissions from these devices do not fall within the definition of "venting." Some stakeholders questioned how the Commission could enforce applications of the definition of venting because of challenges with identifying and proving intent. Though the Commission recognizes these challenges, it was necessary to use the term "intentionally" in the definition of venting to exclude leaks. Additionally, 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. Finally, 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 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.

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 requiring 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 Sundry Notice, Form 4, providing information about volume and content of 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.

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 gas escaping from a well during drilling operations, using the best available technology. 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 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 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 provided a mechanism for operators to submit a subsequent Form 4, Sundry Notice, and where necessary, a Form 23, after the venting occurred, rather than seeking a formal variance from Rule 903.b.(1)'s capture or combustion requirement pursuant to Rule 502.a. Some stakeholders requested that operators submit a gas analysis with their Form 4, Sundry Notice. Although the Commission recognizes that this is required for gas that is vented at later stages pursuant to Rules 903.c.(2).B and 903.d.(3), the Commission does not believe that it is possible for operators to provide a gas analysis for gas vented at the drilling stage, because the emergency nature of such venting would likely make it impossible to capture a sufficient quantity of gas to analyze the sample. 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.

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. The Commission did not specify an efficiency standard for combustion devices used during drilling operations, understanding that the unique characteristics of 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 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. 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 most recent 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. 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 any confusion that might arise from small differences in 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 fully align its completion emissions standards with EPA and the AQCC in Rule 903.c.(1). 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. 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 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.

Rule 903.c.(1)

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 gas in nearly all circumstances. *See* 40 C.F.R. § 60.5375a(a)(4). That leaves only flaring, rather than venting, as an alternative with the Director's prior approval pursuant to Rule 903.c.(2).

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 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. 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 provided standards for operators to obtain the Director's approval to flare gas during completion operations. Operators may either obtain the Director's prior approval when submitting a gas capture plan as an attachment to their OGDP pursuant to Rule 903.e, or by subsequently submitting a Form 4, Sundry Notice. The Form 4, Sundry Notice must include similar information to a gas capture plan, including why the flaring is necessary, 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 Notice to Operators regarding Rule 912.

In Rule 903.c.(2).C, the Commission adopted standards for combusting gas in order to protect safety of onsite personnel and during upset conditions. For this type of unplanned flaring event during completion, operators may obtain the Director's subsequent approval by submitting a Form 4, Sundry Notice, 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.(2).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.(2).C. Consistent with the 100 Series definition of flaring, if salable gas is sent from a well or a separator to an emissions control device, that would qualify as flaring, which is why the Commission adopted standards to regulate such activities in Rule 903.c.(2).C.

The Commission adopted and revised several definitions of terms used in Rule 903.c. First, 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's staff consulted closely with the APCD staff about the appropriate definition, and 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 triggers a variety of different stages, including royalty payments, production reporting, reclamation standards, and lighting standards pursuant to Rule 424, 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, rather than on the presence of permanent production equipment at a location, which is the standard used in the AQCC definition. 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. 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 5As. 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.

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.

Finally, 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 re: Rule 912. The new definition clarifies when flowback begins and ends, and that flowback refers to both a process during well completion and to the fluids that emerge from the well during this process. Several stakeholders raised questions about the final sentence of the definition of flowback, which provides that the flowback period ends when gas is produced in separable quantities, rather than addressing liquid hydrocarbons or specifying that flowback ends when gas is produced in salable quantities. The Commission intentionally chose this language based on extensive consultation with the APCD's staff. The Commission intends for operators to control separable gas as soon as possible. Separable gas can be controlled through capture or combustion prior to gas being produced in salable quantities. Extending the end of flowback to a time when gas is produced in salable quantities, rather than separable quantities, would trigger certain venting and flaring standards in Rule 903 at too late a time in the completion process. The term separable quantities refers to a consistent flow of separable gas. Additionally, the Commission's definition addresses gas, rather than liquid hydrocarbons, because liquid hydrocarbons can be produced before, or after, separable gas, and the Commission is adopting the definition for use in Rule 903 to trigger certain types of venting and flaring standards, which focus on the escape of gas, not liquid hydrocarbons. 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. 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.

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."

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.

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) included 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 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.

Consistent with its efforts to better align its Rules with the AQCC's regulations, the exceptions in Rules 903.a.(1).B, C, and D are intended to address circumstances where the

AQCC's regulations explicitly authorizing venting or 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. Some stakeholders questioned whether the maintenance referenced in Rule 903.d.(1).C includes applying OOSLAT to flowlines. The Commission does intend for Rule 903.d.(1).C to include applying OOSLAT to flowlines. Additionally, some stakeholders raised questions about whether pipeline pigging would fall within any of the exceptions in Rule 903.d.(1). The Commission intends for pipeline pigging to fall within the exception for active and requirement maintenance in Rule 903.d.(1).C.

The fifth enumerated exception in Rule 903.d.(1).E is for 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).E 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).E 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).E, 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.a in the course of seeking approval of their gas capture plans pursuant to Rule 903.e.

Consistent with adopting Rule 903.d.(1).E, 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.

The sixth enumerated exception in Rule 903.d.(1).F is for 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.

The seventh enumerated exception in Rule 903.d.(1).G is for gas vented or flared during liquids unloading that employs best management practices required by AQCC regulations. Because the AQCC regulations do not specify best management practices for liquids unloading, the Commission clarified that operators must flare gas vented during liquids unloading if the escape of the gas poses safety risks. The Commission intends for its staff to work with operators to identify best management practices for liquids unloading on a case-by-case basis. The Commission's intent is to reduce venting associated with manual practices intended for well maintenance. The Commission recognizes that this may require some operators to increase flaring volume capacity.

The eight enumerated exception in Rule 903.d.(1).H is for flaring 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, Sundry Notice 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, 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, C, and E, but adopted the requirement for all of the venting and flaring exceptions except for Rule 903.d.(1).H in order to provide oversight for any unexpectedly long duration venting and flaring events. Consistent with Rules 903.c.(2).B and 903.d.(3), the Commission required operators to report information about the venting and flaring events on a Form 4, Sundry Notice, including the volume and content of the gas vented or flared, a gas analysis, and an explanation of the event. Although local governments should receive notice of all venting and flaring incidents pursuant to Rule 903.a, if a local government needs additional information about the venting or flaring event, it may request access to the Form 4, Sundry Notices from the Commission's staff on a case-by-case basis. For venting or flaring subject to the Rule 903.d.(1).G 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.

Rule 903.d.(3)

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 not connected to gathering lines prior to the effective date of the Mission Change Rules. As was previously required by prior Rule 912.b and the Commission's March 18, 2016 Notice to Operators re Rule 912, operators must submit sundry notices to the Commission to obtain approval to vent or flare gas on an ongoing basis from producing wells. 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 ongoing venting and flaring from producing wells over time. However, the Commission recognizes that some time is necessary for infrastructure issues to be resolved. Accordingly, in Rule 903.d.(3), the Commission provided for at least annual oversight of existing facilities to ensure that they are making progress towards connecting to gathering infrastructure. If the facility is not making adequate progress, then Rule 903.d.(3) grants the Director the authority to deny approval to flare or vent gas at such existing facilities if necessary to protect public health, safety, welfare, the environment, and wildlife resources, or to prevent waste. The Commission codified and slightly modified the specific reporting criteria from the March 18, 2016 NTO in Rule 903.d.(3).A–E. As an added incentive for operators to connect existing wells to gathering infrastructure, the Commission required operators to explain on the Form 4, Sundry Notice, whether the mineral Owner was compensated for the vented or flared 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 by making it clearer to mineral Owners whether they are being compensated for the value of gas wasted through ongoing venting and flaring.

Rule 903.d.(4)

The Commission moved prior Rule 912.c, governing measurement and reporting of 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 gas vented or flared to be reported on a Form 7, 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 gas is "removed from the lease," Rule 903.d.(4).A makes clear that if gas has been removed from a formation, it must be reported on a Form 7.

The Commission adopted a new Rule 903.d.(4).B requiring operators to expand reporting requirements about the volume of 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 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 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.

Rule 903.d.(6)

The Commission moved prior Rule 805.b.(2).C, to Rule 903.d.(6).A. The Commission made relatively few changes to the Rule, except to reduce the permissible VOC emissions from pits from five tons per year to two tons per year. The Commission intends for this regulatory change to apply retroactively to existing pits that are located within 2,000 feet of a Building Unit or Designated Outdoor Activity Area 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, and that five tons per year of VOC emissions is too great a health risk in such close proximity to areas where people live and recreate. Some stakeholders questioned whether Rule 903.d.(6).A would apply to pits where a building unit was built or a designated outdoor activity area was designated after the pit was already constructed. The Commission does intend for rule 903.d.(6).A to apply in such a situation, consistent with prior Rule 805.b.(2).C using the term "located" rather than "constructed." Additionally, some stakeholders raised questions about the meaning of the term "uncontrolled actual." This is language that the Commission did not change from prior Rule 805.b.(2).C. The Commission determined that it is appropriate to continue using this language because it is consistent with language used by the AQCC regulations applicable to oil and gas operations. *See generally* 5 C.C.R. § 1001-9:D.II.

The Commission adopted a new Rule 903.d.(6).B, governing emissions from new pits. The Commission provided that new pits may not have VOC emissions that exceed five tons per year, regardless of their proximity to building units or designated outdoor activity areas. The Commission determined that this is an important step to reduce emissions of VOCs and methane that may harm public health, welfare, the environment, and wildlife resources.

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 4, Sundry Notice within 1 year for existing pits, and on a Form 15, Pit Permit, for new pits. 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). For new pits, the Commission anticipates that the analysis of dissolved and entrained VOCs in produced water source analysis will provide a reasonable indication of emission rates. However, the Commission may consider requiring conditions of approval to monitor and model actual pit emissions on a case-by-case basis as appropriate.

Rule 903.e

The Commission adopted a new Rule 903.e, requiring operators to submit gas capture plans as an attachment to Form 2As 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 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.

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, 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 Rule 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. 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.

In Rules 903.e.(2) and (3), the Commission adopted standards to ensure that operators comply with the 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 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. Pursuant to Rule 301.d, operators may request a modification to their gas capture plan if unforeseen circumstances make the operator unable to connect to a gathering line or comply with their plan. Rule 301.d specifies the process for the Director, and if necessary, the Commission, to approve modification to the terms of an OGDP, including gas capture plans. The Commission also specified that operators may request a hearing before the Commission pursuant to Rule 503.a.(10) if the Director requires a well to be shut in because it did not connect to a gathering line 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 Mission Change Rulemaking implement the Commission's statutory obligation to evaluate and address cumulative impacts, including Rules 303, 314, 423, 424, 426, and 427. However, in consultation with CDPHE, the Commission determined that further evaluation of cumulative air and climate 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. One barrier to successful evaluations in the past has been challenges with securing voluntary operator participation in the studies. Accordingly, in Rule 904.a, the Commission clarified its authority to require operators to participate in studies evaluating cumulative air emissions impacts as a condition of approval on an OGDP pursuant to Rule 307.b.(1). In Rule 904.b, the Commission further specified its intent for the 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 air emissions impacts to solely these subjects, and accordingly used the phrase "will include, but not be limited to," in 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, 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.

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.a 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 Rules 913.h.(2) and 915.e.(2).C without 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.

Rule 905.a

Rule 905.a.(1)

The Commission did not substantively revise Rule 905.a.(1), other than changing its language to match the 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. 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 three criteria: final disposition of the waste, a proposed timeline for reuse and recycling, and any additional information requested by the Director. The Commission added these criteria to facilitate its purpose of encouraging the reuse and recycling of E&P Waste, including produced water. 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. 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 produced water for reuse and recycling may be greater than not reusing and recycling produced water. 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 ("OGDPs"). 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 that appears in prior Rule 907.a.(3), product quality assurance, in Rule 905.a.(3).D. 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 produced water recycling process. 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 or 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, 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 results 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 to the oil and gas location 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. 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).B. The Commission intends for this requirement to be consistent with the significant/insignificant dichotomy encapsulated by Rule 404, governing Form 4, Sundry Notices.

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 a location where a prior remediation project was completed and closed, including 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. The Commission received robust stakeholder feedback about proposed Rule 905.a.(5) in its February and May Straw Dog drafts of the 900 Series. The Commission solicits additional stakeholder feedback about Rule 905.a.(5) in party prehearing statements to allow the Commission to continue evaluating the proposed rule.

Rule 905.b

The Commission moved prior Rule 907.b, governing E&P Waste transportation, to Rule 905.b. The Commission did not substantively revise Rule 905.b.(1) or (2), but made minor wording changes to improve clarity and broke prior Rule 907.b.(1) into two subsections to provide further clarity. 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. § 261.21. 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 prevents adverse impacts to groundwater. 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 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).A.iii 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, made minor clarifications to the wording, updated cross references, capitalized defined terms, and updated incorporations by reference, but did not make substantive changes to the Rule. The Commission moved prior Rule 907.c.(2).F to Rule 905.c.(2).E and made similar non-substantive changes.

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 Rule 431.b, 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 OGDP applications pursuant to Rule 904.b.(17), 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, Sundry Notice 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 Rule 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 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 method 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 required. Third, consistent with the Commission's 1000 Series Rules, the Commission prohibited application of water-based bentonitic drilling fluids 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 disposal at commercial facilities. 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, surface owners, and time investment by the Commission's environmental protection specialists. The Commission 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.

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 was "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 permitted 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 six 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).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.

Third, 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.

Fourth, 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.(1).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.(1).H.i, which would involve spreading oily wastes on lands that were not previously disturbed by the oil and gas operations.

Fifth, 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.

Sixth, in Rule 905.e.(2).H, the Commission required operators to complete land treatment within three years. If operators do not complete land treatment within three years, then the operator must submit a Form 28 application to convert the location into a centralized E&P Waste management facility. The purpose of Rule 905.e.(2).H 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. 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 provide this clarity 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 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.

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 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 disposal 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 Technologically Enhanced Naturally Occurring Radioactive Material ("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. At the time of the 800/900/1200 Mission Change Rulemaking, CDPHE's Hazardous Materials and Waste Management Division ("HMWMD") had proposed draft TENORM rules, but the rulemaking was still in process. Accordingly, the Commission determined that it was inappropriate to adopt its own TENORM regulations, if any, prior to CDPHE completing its rulemaking process. However, the Commission added two isotopes of radium (^{226}RA and ^{228}RA), as well as isotopes of lead (^{210}Pb), bismuth (^{210}Bi), and polonium (^{210}Po) 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 805.c. The Commission determined that this data is important to help characterize the presence of 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 same five isotopes that the HMWMD defined as TENORM Radionuclides in its proposed 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.

In Rule 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 Rule 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 local government land use regulations and facility siting, operation, and construction requirements. Finally, 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), in Rule 907.b.(5).G, the Commission required that centralized E&P Waste management facilities be located at least 2000 feet from the nearest building unit or high occupancy building unit, unless all building unit owners within 2000 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 seven 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.(5).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 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.

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 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.

Rule 907.c

In Rule 907.c, the Commission substantially revised its standards for approval, denial, and approval with conditions 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), (11)(b), (12)(b), (13)(b); 34-60-106(2.5), C.R.S., the Director may approve centralized E&P Waste management facility permits 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.(2), 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. The Commission chose not to limit the 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 Professional Commission will allow for a more timely and efficient hearings schedule which will impacts 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, Sundry Notice.

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 two-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.

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.

APPENDIX B

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 because it could provide adequate environmental protection by instead strengthening seven of 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 and existing pits through fences, netting, and other exclusion methods approved by CPW in Rules 603.h, 909.f, and 1202.a.(4). Third, the Commission adopted new emissions standards for all pits statewide in Rule 903.d.(6).B, strengthened emissions standards for existing pits near building units 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 910, 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 unused equipment 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, Earthen Pit Permit 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 Pit Permit, 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 Pit Permit. 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 15, Earthen Pit Permits 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, Earthen Pit Permit, 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), (11)(b), (12)(b), (13)(b); 34-60-106(2.5), C.R.S., 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, Earthen Pit Permit 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 November 2, 2020—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 November 2, 2020. However, the Commission does intend for components of Rule 909 that involve ongoing activities or operations that occur at existing pits after November 2, 2020 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 has 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 respective 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, 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, Earthen Pit Report 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 the standards prohibiting the presence of liquid hydrocarbons in a pit in prior Rule 902.c. 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 substantially revised prior Rule 902.d, governing fencing and netting pits. The Commission required that all new and existing pits must be fenced, and either netted or covered with another wildlife exclusion method approved by Colorado Parks and Wildlife pursuant to Rule 1202.a.(4). The Commission intends for Rule 909.f to apply retroactively to existing pits, as well as applying to new pits. The Commission recognizes that this will require some operators to retrofit existing pits that are not already fenced and netted. However, 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 pits. Because the risk of wildlife mortality exists regardless of a pit's construction date, the Commission determined that it is necessary and reasonable to require fencing and netting of all pits in active, ongoing operation to exclude wildlife.

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, but did not substantively revise the requirements of the Rule. 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.

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 Rule 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 the State of Colorado. 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 UIC wells pursuant to Rules 803.g.(5).C & D, 803.h.(1), and 805.c. The full suite of analytical parameters will allow the Commission to better characterized the characteristics of 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.

Several stakeholders raised questions about the frequency of sampling required by Rule 909.j. The intent of Rule 909.j is to require only one-time sampling of produced water placed in pits. 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 first sample, and 1.5 years to submit the 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 samples and process and review the data. The Commission authorized that the Director, where necessary based on information provided by the first sample, may also require subsequent sampling.

<u>*Rule 909.j.(1)*</u>

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, lead, bismuth, and polonium in Rule 909.j.(1).K. As discussed above, the Commission determined that it is necessary and reasonable to require testing for these radioactive and daughter 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 the four radioactive and daughter isotopes because they are the isotopes defined as TENORM Radionuclides in CDPHE's Hazardous Materials and Waste Management Division's May 4, 2020 proposed TENORM regulations. *See* Proposed 6 C.C.R. § 1007-1:20.2 (May 4, 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 radiological 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 isotopes defined as TENORM Radionuclides in

CDPHE's proposed TENORM regulations, which will provide a first step towards radiological profiling of produced water samples.

Rule 909.j.(2)–(4)

In Rules 909.j.(2)–(4), the Commission adopted clear sampling and reporting protocols for produced water samples collected pursuant to Rule 909.j.

Rule 909.j.(5)

In Rule 909.j.(5), the Commission clarified that it does not intend for operators to be required to sample all produced water that is transferred to 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. Because the produced water received by such facilities 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 centralized E&P Waste management facilities, 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. 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. First, Rule 909.j.(5) provides the Commission with representative produced water quality data from produced water formations. Second, Rule 909.j.(5) 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 water-based bentonitic drilling fluids, which do not contain materials that pose a risk of contamination to soil, surface water, or groundwater. 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 applying 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 modelling.

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 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 two weeks 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 within two weeks of the effective date of the 800/900/1200 Mission Change Rulemaking, but rather to submit a Form 27 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 made 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, Site Investigation and Remediation Workplan, 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.[5] Facility closure is the time when spills are most often reported, 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 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 adopted a new Rule 911.c, governing inactive oil and gas facilities, which

[5] https://cogcc.state.co.us/documents/library/Technical/Risk_Based_Inspections/DNR%20-%20OGCC%20Risk%20Based%20Inspection%20Strategy%20FINAL.pdf

were previously only addressed by prior Rule 603. Rule 911.c requires operators to report unused equipment at oil and gas locations, including pits, if the equipment is not used for more than one year on a Form 4, Sundry Notice. Operators must describe the need for continuing to keep the unused equipment at the location, and obtain the Director's approval to continue to keep the unused equipment at the location. The Commission also required operators to properly maintain equipment that is not in use that is kept at an oil and gas location. The Commission adopted Rule 911.c because storage of unused equipment at oil and gas locations has posed safety, environmental, and wildlife risks in the past, and also posed significant challenges during the remediation and reclamation processes. Additionally, the Commission's orphan well program has become responsible for removing unused equipment at many locations. The Commission determined that one year is an appropriate time period to allow operators to keep unused equipment at an oil and gas location, that strikes the balance between avoiding unnecessary paperwork for operators while still providing important remediation and reclamation benefits. The Commission specifically chose one year as the time duration before unused equipment must be removed in recognition that operations in some areas of the state are seasonal due to weather or wildlife timing restrictions. Some stakeholders requested that the Commission adopt a provision allowing surface owners or other affected persons to petition the Commission to require an operator to remove unused equipment from an oil and gas location. The Commission did not adopt this requirement because surface owners and other affected persons may already request removal of unused equipment through the complaint process pursuant to Rule 524.

Rule 911.d

The Commission moved prior Rule 905.b, which provides specific standards for closure of pits, to Rule 911.d. The Commission made only minor non-substantive changes to the Rule, except for clarifying in Rule 911.d.(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.d 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.

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. 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 906.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 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 "immediately."

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 that the Director 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. § 34-60-103(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.

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 revise Rule 912.b.(1).C. However, 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 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.

The Commission adopted a new Rule 912.b.(1).F, 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 new materials from an historic release, the Commission determined that ten cubic yards is a reasonable threshold. In Rule

912.b.(1).F, 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).F is reporting, not remediation. Rule 912.b and all of its subsections, including Rule 912.b.(1).F, 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 Rule 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).F 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).F, the Commission also adopted a new Rule 912.b.(1).G, 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).H, 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 & 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).H 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).H 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).H clarifies that the spill is suspected to be reportable.

In Rule 912.b.(1).I, the Commission adopted a new requirement that operators report spills or releases of vaporized mists that leave an oil and gas location. The Commission determined that it was necessary to adopt Ruel 912.b.(1).I, because the volume of vaporized mists are very difficult to calculate, and even a relatively low volume of a vaporized fluid may spread across and impact a relatively large area. The Commission further determined that it was necessary to adopt Rule 912.b.(1).I, because its Staff have received numerous complaints about vaporized mists leaving an oil and gas location and impact 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).J, 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).K, 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 Rule 912.b.(1).J & K 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 of subsurface natural gas releases until testing can be conducted to identify whether natural gas is thermogenic or biogenic in origin.

Rule 912.b.(2)

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 in 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 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 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 supplemental Form 19 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 Spill/Release Report to close the spill because it has been fully cleaned up in compliance with Table 915-1, or a Form 27, Site Investigation and Remediation Workplan, 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 the 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 Rule 411.b, the Commission also described the procedures for reporting spills or releases that impact or threaten to impact Public Water System intakes.

Rule 912.b.(10)

The Commission adopted a new Rule 912.b.(10), requiring spill and release reporting to Colorado Parks and Wildlife 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 Stake 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.

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 serve 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).H 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).H 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 Permits, the Commission adopted a new Rule 912.f requiring the new operator of a transferred facility with an active Form 19 to file a supplemental Form 19, designating which 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.

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 912.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 909.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 909.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 may be 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 open excavation, 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 cause unnecessary surface disturbance, inhibit effective reclamation, and cause adverse impacts to other resources that may exceed 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 subsect previously requirement 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 is necessary.

In Rule 913.c.(9), the Commission required a Form 27 submission for decommissioning oil and gas facilities. 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.(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 have 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.

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, 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. Some stakeholders suggested that the Commission adopt a firm limit on the duration of 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 a time limit for remediation project in its forthcoming Financial Assurance Rulemaking, including whether it will require operators to provide financial assurance if remediation is not complete within a specific timeframe.

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, Transfer of Permits, the Commission adopted a new Rule 913.g requiring the new operator of a transferred facility with an active Form 27 to file a supplemental Form 27, designating which 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 Director pursuant to Rule 502.a, rather than from the Commission pursuant to Rule 502.b, to comply with an alternate standard instead of the standards listed in Rule 913.h.(1). The Commission recognizes that local soil and groundwater characteristics vary across the state and intends for operators to be able to obtain disposition to comply with alternate standards so long as those alternate standards are at least as protective as the standards in Rule 913.h.(1).

In Rule 913.h.(3), the Commission provided, for remediation projects which are subject to periodic monitoring, those projects 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 sued for site closure in other regulatory programs.

In Rule 913.h.(3), 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.

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.

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 U.S. 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.c 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.

The Commission identified specific elements, compounds, and parameters that the Director may require operators to conduct additional sampling for in Rules 915.d.(1) & (2). Rule 915.d.(1) references the WQCC's Regulation 41 numeric groundwater quality standards. Rule 915.d.(2) references the WQCC's Regulation 41.5 narrative groundwater quality standards. 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 41.5 standards in Rule 915.d.

<u>Rule 915.e</u>

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 Rule 915.e and 901.b. The Commission will also allow operators to use analytical method 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.

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 replaced 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 specified 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 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.(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 from the Director pursuant to Rule 502.a.

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.(4).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 Commission 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*.

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

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.

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.

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 also raised questions about the cleanup concentrations for certain organic compounds in groundwater, including benzene, toluene, ethyl benzene, and xylenes ("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 adjacent background concentrations or reference levels in nearby soil and groundwater. Because of the high volume of stakeholder questions about the RSL for arsenic, the Commission also specified in Table 915-1 that an alternate acceptable cleanup concentration for arsenic is 1.25 times above local background levels. The Commission determined that this is an appropriate mechanism to address variations in background arsenic contamination 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.

<u>1200 Series – Protection of Wildlife Resources</u>

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 19-191 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). Complimentary to this hierarchy is Senate Bill 19-181's mandate that the Commission, at a minimum, adopt an alternative location analysis process for oil and gas locations that are proposed 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. 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 Mission Change Rulemaking 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. An additional major change is the removal of wildlife habitat maps from Appendices VII and VIII, as the prior process for updating the wildlife habitat maps only through formal rulemaking led to stale and outdated maps and resulted in uncertain protection of various wildlife species.

The Commission and Colorado Parks and Wildlife (CPW) prepared a Frequently Asked Questions (FAQ) document to provide context for some of the changes being proposed in the rulemaking. The document is intended to evolve and be updated as questions arise from stakeholders as the rules are implemented. The FAQ for the May 1, 2020 Straw Dog draft rules is attached as Attachment 1 because it provides additional context for the Commission's Rules. As with other change 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, 500, 900 and 1200 Series Rules. High Priority Habitat is an accepted 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 Rules.

Maps showing and spatial data identifying the individual and combined extents of the High Priority Habitat areas will be provided by CPW and made available on the Commission's website. The extent of these habitat areas is subject to update by CPW on a periodic but no more frequent than annual basis. Notice of any map update will be posted on the Commission's website 90 days in advance of the update and will specify the date new maps will be available on the Commission's maps and include applicable information or spatial data. To ensure that operators are able to efficiently plan their developments, map updates do not apply to any Form 2A Oil and Gas Location Assessment or Oil and Gas Development Plan if, at the time of the update, the Commission has deemed the Form 2A or OGDP complete pursuant to Rule 303.b or Rule 304, respectively.

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.

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, local government, or surface owner desires. By creating breadth in the definitions and types of plans, the Commission encourages operators to incorporate landscape-level planning into its 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.

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.

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. Important objectives of the consultation are for the Commission and operator to obtain the best available information from CPW regarding potential impacts to wildlife resources. The nexus for CPW consultation is a potential impact to wildlife resources, which is reflected in Rule 309.e.(2).A.–F. In Rule 309.e.(2).D., the Commission included the term "other matter" to include consultations when the facts on the ground identify a wildlife resource that needs consideration—again, there must be a nexus to wildlife resources. There are also circumstances in which CPW consultation is not necessary—largely attributable to early coordination between the operator and CPW, which is why Rule 309.e.(2).G allows CPW to waive consultation at any point, and why the Commission articulated circumstances in which consultation is not required in Rule 309.e.(3).

Recognizing that in Colorado, many of impacts to wildlife resources intersect federally-owned surface, development of federal minerals, and management of species listed as threatened or endangered under the federal Endangered Species Act (ESA) and their critical habitat, the federal government has an important role in supporting and bolstering the State's actions to protect wildlife resources. The Commission and CPW will continue to work closely with the Bureau of Land Management (BLM), especially with respect to its plans for development on federally-owned surface. In addition, CPW will coordinate consultations related to federally listed species and their critical habitat with the United States Fish and Wildlife Service (USFWS). Coordinating with BLM, as a federal land manager, early in the process is important to achieving complimentary permitting outcomes, and therefore, 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 U.S. 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). 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 authorize 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, 687–69 (10th Cir. 2019) (discussing 16 U.S.C. §§ 528, 1604(a); 43 U.S.C. § 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.

The Commission's proposed revisions to Rule 309 included changes to the wildlife protection plan that will require conforming changes to Rule 304.c.(17), which the Commission noticed with the Secretary of State as part of the 100 through 600 Series Mission Change Rulemaking. Staff will recommend the conforming change as part of the 100 through 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. 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 Procedures Act (APA), C.R.S. § 24-4-104—always apply to actions by the Commission or CPW. Rule 309.e does not cede Commission's permitting authority to its sister agency, but instead emphasizes the importance of cooperative analysis and consultation to achieve necessary wildlife resource protection.

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 part of 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 generally creates the framework and varying tools available for operators to plan for operations that may or will impact wildlife resources. The Commission designed these tools to be flexible and encourage coordination with the federal government and CPW, and landscape level planning.

Rule 1202.

In Rule 1202, the Commission updated, adapted, and added to operating requirements and restrictions relating to protection of wildlife resources. The statewide operating requirements in Rule 1202.a are generally accepted by the Commission and CPW as appropriate measures to minimize impacts to wildlife resources. However, CPW may waive the requirements, as appropriate, based on site-specific considerations. Statewide operating practices will be described in the operator's wildlife protection plan. For site-specific surface management requirements, the Commission will work with BLM and other federal surface management agencies on federally owned or managed surface.

Similar to the statewide requirements, Rule 1202.b. articulates additional operating requirements that apply to operations within High Priority Habitat. Given the importance of this habitat, the Commission determined that additional requirements were appropriate. Site-specific measures and best management practices will be described in an operator's wildlife mitigation plan for sites intersecting High Priority Habitat.

In Rules 1202.c. and 1202.d, the Commission modified its prior restricted surface occupancy and no surface occupancy Rules to align the restrictions to the High Priority Habitat system, and to conform to CPW's current recommendations for habitat and species protections. The habitats listed in Rule 1202.c. are the most sensitive wildlife resources and are supported by robust data in the administrative record provided by CPW demonstrating that avoidance is the single most effective protection strategy. Therefore, Rule 1202. is the most prohibitive of oil and gas operations. For Rule 1202.c., the Commission received some feedback regarding the distances for eagles. The Commission adopted distances based on federal surface restriction distances, rather than distances appropriate for federal timing stipulations. Stakeholders also suggested that Rule 1202.c standards for Gunnison sage-grouse are insufficiently protective. The Commission adopted the Rule 1202.c standards based on consultation with CPW, and the standards are based on the best available scientific information and are fully compliant with the federal ESA protections for Gunnison sage-grouse and its critical habitat.

The habitats listed in Rule 1202.d., while sensitive, are frequently managed using impact minimization strategies. 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.

Rule 1202 represents a statewide approach the Commission believes appropriate to protect wildlife resources. However, in unusual circumstances an operator may request a variance pursuant to Rule 502.b for consideration by the Commission, which would also require consultation with CPW pursuant to Rule 309.e.(2).E.

Rule 1203.

In Rule 1203, the Commission created alternatives for operators to address compensatory mitigation for direct impacts or unavoidable adverse indirect impacts through either performance of a compensatory mitigation plan or payment of a fee. 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

The Commission received robust feedback on the concept of a 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. Important to evaluating whether a fee is appropriate on federal surface estate on a case by case basis will be coordination with the BLM to assess how the federal government will consider and minimize or mitigate impacts from the proposed operation.

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 are those related to physical land disturbance and vegetation removal resulting in habitat loss. Indirect impacts extend beyond physical 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. However, Rule 1203 only requires mitigation of indirect adverse impacts that cannot be eliminated through the application of alternative location selection or other methods designed to minimize adverse impacts. Again, this narrow approach to mitigation of 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.

The Commission included a tiered approach to the direct impact mitigation fee. In the Commission's and CPW's experience, most oil and gas locations are less than 11 acres.

Therefore, the Commission and CPW have more experience understanding the 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 will require a more in-depth review to understand and mitigate impacts. The FAQ in Attachment 1 provides additional information about how the fee and compensatory mitigation function. The fee can be adjusted by the Commission, as appropriate, with changes to costs. The FAQ clarifies that fees paid 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 will 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.

Where operators choose to conduct mitigation projects of their own, 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.

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 August 24 and September 10, 2020. Pursuant to C.R.S. § 24-4-103(5), these amendments will become effective on November 2, 2020, unless otherwise specified in the Rule.

COLORADO Parks and Wildlife Department of Natural Resources

COLORADO Oil & Gas Conservation Commission Department of Natural Resources

FAQ for May 1, 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?

In 2009, when the COGCC promulgated rules to implement HB 07-1298, Colorado Parks and Wildlife (CPW), formerly known as Colorado Division of Wildlife, 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.

CPW's 2009 recommendations were developed internally by a team of subject matter experts who consulted with peers in other agencies and academic institutions. The HPH list does not cover all wildlife species in Colorado, it does however cover those species and habitats that concern CPW 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. Since 2009, CPW has continued updating the HPH to reflect current research or management recommendations.

During the HB 07-1298 rulemaking, a subset of HPH were re-labeled Sensitive Wildlife Habitat (SWH) and Restricted Surface Occupancy (RSO) areas. The proposed draft rules simplify the nomenclature and mapping to be consistent with how CPW categorizes, labels, and maps species activities and habitats to implement SB 19-181's directives. The updated HPH list includes the previous SWH and RSO species and habitats with the addition of species and habitats for which the best available science warrants a management recommendation for wildlife protection.

The HPH identified in proposed Rule 1203.c. are analogous to the RSO areas under existing Rules. Similarly, the more encompassing CPW HPH consultation triggers outlined in proposed Rule.309.e(1)A. are analogous with SWH under existing Rules.

2) How will COGCC and CPW implement an Alternative Location Analysis as described in proposed Rule 304.b.(2).A.iv.?

The overarching goal of the proposed rule is for operators to avoid HPH to the extent feasible and work with CPW in a pre-application period to identify oil and gas locations. For oil and gas locations in high priority wildlife habitats where avoidance is not feasible, the operator and CPW can work together to identify locations that minimize impacts to the greatest extent achievable.

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 choose locations that avoid or minimize adverse impacts to wildlife. As a result of this informal "pre-consultation," CPW may waive the wildlife portion of the Alternative Location Analysis (ALA) submitted with the Form 2A location assessment application if an operator demonstrates that it has selected a location that avoids or minimizes impacts to wildlife. The outcome of the pre-application period can be formalized into a Wildlife Mitigation Plan that addresses one or multiple locations or memorialized in a Wildlife Protection Plan. The pre-application review may also occur as part of a local or federal permitting process.

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 the location's impacts to wildlife. The ALA will contain information on alternative locations that were considered to avoid and minimize impacts to wildlife, including locations recommended by CPW during a pre-application review, and a narrative explaining why these locations were ultimately not feasible for locating the proposed oil and gas facilities.

3) What is a Wildlife Protection Plan, Wildlife Mitigation Plan, or other conservation plan as described in proposed Rules 309.e.(2).B. and 1203.d., 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 (WPP)** is the plan specific to new or amended Form 2A Location Assessments, Oil and Gas Development Plans, and Comprehensive Area Plans that describe operating practices and measures that will be implemented to avoid, minimize, and mitigate impacts to wildlife resources. The required contents of a WPP are outlined in proposed Rule 1201.

A **Wildlife Mitigation Plan (WMP)** references a type of plan that was originally implemented under existing 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 multiple wells, usually on a landscape scale meaningful to address fragmentation and cumulative impacts to wildlife. Some operators have ongoing WMPs, and this concept was carried over into the proposed rules. WMPs differ from Comprehensive Area Plans in that they only address impacts to wildlife resources. Operators still have the opportunity to complete WMPs with CPW under the new rules.

Other **conservation plans** refers to plans to avoid, minimize, and mitigate impacts to wildlife implemented through other programs that were 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 proposed rules. Examples of other conservation plans may include, but are not limited to: Habitat Conservation Plans for threatened and endangered species, Candidate Conservation

Agreements, and wildlife plans adopted pursuant to local government regulations or through a federal permitting process.

4) **Under existing rules the consultation period for CPW was 40 days, now it is proposed to be 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 existing Rule 306.c.(2).C. 40-day consultation period. The addition of 20 days was intended to allow added time for unique instances where compensatory mitigation projects must be negotiated as a substitute for the flat mitigation fee. Additionally, in rare instances where the consultation process includes more complex discussions regarding wildlife protections, additional time may be needed to facilitate the back and forth nature of these negotiations. CPW does not intend to change our consultation practices and does not anticipate a substantial number of consultations requiring the full 60 days to complete. Further, successful consultations conducted during the pre-application period may result in expedited CPW review and processing time including the waiving of certain requirements.

5) **Several of the proposed Rules reference obtaining a "waiver" from CPW (e.g., 304.b.(2).A.iv., 309.e.(1).G., 309.e.(4), 1203.a., and 1203.b.). How does an operator obtain a waiver from CPW?**

Waivers from CPW may be obtained during an informal pre-application period or during the formal consultation process that starts with filing 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 proposed Rule 309.e.(4), CPW may waive any of the operating and mitigation requirements required by proposed Rule 1203 and 1204 if the operator demonstrates to CPW's satisfaction that the protection for wildlife afforded by the measures outlined in proposed Rule 1203 and 1204 are met or exceeded (through an approved Wildlife Mitigation Plan or other site-specific or comprehensive plan).

6) **If electing to complete their own mitigation rather than paying a mitigation fee under proposed Rule 1204, how does an operator complete the mitigation in a timely way that doesn't delay their permit?**

CPW and COGCC 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 access to subcontractors to implement mitigation projects quickly and efficiently. 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 or can be identified 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 into the consultation as a recommended Condition of Approval.

7) How was the mitigation fee calculated and how will CPW spend the mitigation money that it collects?

Disturbance acreage values from Form 2A locations submitted over the last two years (2018 & 2019) were averaged across the state. These acreage values include an average long-term disturbance (i.e. working pad and road surface) and average short-term disturbance (i.e. areas where interim reclamation occurs after 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' (DOLA) five-year (2014-2019) average cost per acre to implement permanent conservation easements in Colorado. Short-term mitigation costs were obtained by averaging CPW's costs to implement short-term habitat enhancement projects in Colorado.

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.

8) What are "indirect impacts" referenced in proposed Rule 1204, 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 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 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 (i.e., 1 Oil and Gas Location per square mile or less) to high density (i.e., 4 Oil and Gas Locations per square mile or more). 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 proposed Rule 1204.d.(2). CPW will use those factors to determine if additional compensatory mitigation is warranted to offset residual unavoidable impacts for individual Form 2As during the consultation with Operators.

9) How are cumulative impacts to wildlife resources being addressed in the proposed 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 (WPP) into every new and amended Form 2A per proposed Rules 304.c.(17) and 1201 will reduce direct, indirect, and cumulative impacts to wildlife resources. As proposed, the WPP will describe any Rule 304.b.(2).A.iv. pre-application Alternative Location Analysis that was completed to identify and avoid impacts to wildlife, Rule 1203 operating practices designed to minimize site-specific impacts at the location that has been selected, and Rule 1204 mitigation commitments of offset unavoidable adverse impacts.

The species-specific development buffers outlined in proposed Rule 1203.c. will help reduce cumulative impacts to the applicable species. Likewise, proposed Rule 1203.d. provides the opportunity to address cumulative impacts to species known to be adversely impacted by Oil and Gas Location densities in excess of 1 per square mile. Finally, the Rule 1204 requirement to complete mitigation to offset unavoidable direct and indirect impacts, as proposed, will greatly reduce cumulative impacts to wildlife resources.

10) How will the consultation process be implemented on federal surface or minerals?

The COGCC and CPW currently enjoy a productive and cooperative relationship with respect to permitting on federal surface. CPW routinely provides input regarding wildlife and wildlife habitat protection during the National Environmental Policy Act (NEPA) process and COGCC and DNR share a memorandum of understanding with respect to permitting processes on federal jurisdictional surface or minerals. The COGCC 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 impacts, the Bureau of Land Management may provide valuable insight to potential mitigation projects.

ATTACHMENT 2

ATTACHMENT 2

COGCC Mission Change Rulemakings Reorganization Crosswalk

As part of its Mission Change Rulemaking and 800/900/1200 Mission Change rulemaking, the Colorado Oil and Gas Conservation Commission has proposed reorganizing several series of its Rules. This reorganization will improve 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 to be in a more logical, sequential order that better reflects the sequential processes that occur on the ground.

Current Rule Number (as of June 19, 2020)	Reorganized Rule Number
201	201
202	202
203	203
204	204
205	206; 208
205A	208; 201
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
303	302; 303; 304; 308; 310; 311.
304	306
305A	302
305	302; 306; 307; 309; 412; 605
306	302; 309; 412
307	404
308A	414
308B	416
308C	206, 409
309	413

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310	217
311	435
312	218; 219
313	*Removed*
313A	*Removed*
313B	220
314	420
315	224
316A	807
316B	418
316C	405
317	408; 603; 903
317A	409
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	804
324D	914
325	805; 806; 808; 809
326	417
327	428
328	429
329	430
330	431
331	432
332	433
333	313; 436
334	221
335	908
336	222
337	912
338	*Removed*
339	*Removed*
340	913
341	419

401	810; 811
402	810
403	810
404	810
405	803; 810
501	501
502	502; 503
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520	*Removed*
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528	507; 510
529	529
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531	519
532	520
533	521
601	601
602	602
603	421; 603; 604; 605; 606; 607
604	408; 603; 604; 606; 608; 903
605	603; 608

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606A	610
606B	611
607	612
608	614; 615
609	615
801	422
802	423
803	424
804	425
805	426; 427; 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