COST-BENEFIT ANALYSIS AND REGULATORY ANALYSIS

DEPARTMENT:	**DEPARTMENT OF NATURAL RESOURCES**	**AGENCY:**	**COLORADO OIL AND GAS CONSERVATION COMMISSION**
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INTRODUCTION

This serves as the combined cost-benefit and regulatory analysis ("Analysis") for the Colorado Oil and Gas Conservation Commission's ("Commission") rulemaking that the Commission noticed via publication in the Colorado Register on July 10, 2020 (tracking number 2020-00435). The Commission refers to this rulemaking as the "800/900/1200 Mission Change Rulemaking" because of its sweeping nature and scope.

1. **Legislative Background**

Understanding the legislative context for the 800/900/1200 Mission Change Rulemaking provides necessary background information to assess the scope of the costs and benefits of the Commission's draft 900 and 1200 Series Rules addressed in this Analysis. During the 2019 legislative session, the Colorado General Assembly adopted Senate Bill 19-181 (concerning additional public welfare protections regarding the conduct of oil and gas operations) ("SB 19-181"). This bill significantly amended the Colorado Oil and Gas Conservation Act ("Act"), C.R.S. §§ 34-60-101–131, both substantively and procedurally. SB 19-181 requires the Commission to undertake three specific rulemakings: one to implement changes to the agency's mission, one to adopt an alternative location analysis process, and one to evaluate and address potential cumulative impacts of oil and gas development. C.R.S. §§ 34-60-106(2.5)(a) and (11)(c)(1), and 34-60-104(1)(b). Because these three topics are fundamentally interrelated, the Commission chose to address them in the Mission Change Rulemaking. Because of the broad scope of the General Assembly's instructions to the Commission, the Commission bifurcated the Mission Change Rulemaking into two separate rulemaking hearings. The first addressed amendments to the Commission's 200–600 Series Rules and was subject to a previous cost-benefit analysis, which was published on August 14, 2020. The second, addressing amendments to the Commission's 800, 900, and 1200 Series Rules, is the subject of this Analysis.

The General Assembly also directed the Commission to consider other key amendments to the Act when drafting the 800/900/1200 Mission Change Rulemaking rules. Among other things, the General Assembly made the following changes in SB 19-181, all of which Commission Staff ("Staff") thoughtfully assessed when drafting the proposed rules:

- C.R.S. § 34-60-106(2.5)(a) (additional powers of the Commission) ("Mission Statement Section")

This section sets forth the Commission's powers and requires the Commission to consider certain factors when exercising its authority under the Act. The Section now requires that the Commission "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." (emphasis added).[1]

Prior to this change, the Act gave the Commission discretionary authority to regulate "[o]il and gas operations so as to prevent and mitigate *significant adverse environmental impacts* on any air, water, soil, or biological resource … *to the extent necessary* to protect public health, safety, and welfare, including protection of the environment and wildlife resources, *taking into consideration cost-effectiveness and technical feasibility*." C.R.S. § 34-60-106(2)(d) (2018) (emphasis added).

- C.R.S. § 34-60-103(5.5) (definition of "Minimize adverse impacts")

In conjunction with amending the Mission Statement Section, the General Assembly also substantively modified the definition of "Minimize adverse impacts." Pursuant to the new definition:

1. The term applies "to the extent necessary and reasonable to protect public health, safety, and welfare, the environment, and wildlife resources." Prior to the change, the term applied only "wherever reasonably practicable."
2. The term no longer requires that the Commission "[t]ake into consideration cost-effectiveness and technical feasibility with regard to actions and decisions taken to minimize adverse impacts to wildlife resources." *Compare* C.R.S. § 34-60-103(5.5) (2020) *with* § 34-60-103(5.5)(d) (2018). Notably, the prior version of the Act only took cost-effectiveness and technical feasibility into consideration with respect to wildlife resources. By removing this requirement, the Act no longer requires the Commission to take these factors into consideration when the Commission takes *any* actions to protect: (1) public health, safety, and welfare; (2) the environment, or (3) wildlife resources.

In addition, the Commission must "minimize adverse impacts" in new and revised substantive Act provisions. *See* C.R.S. §§ 34-60-106(2.5) (Mission Statement Section) and (19) (requiring the Commission to amend its flowline rules); 34-60-128(3)(b) (regarding habitat stewardship rules).

- C.R.S. § 34-60-103(11)–(13) (definition of "Waste")

The General Assembly revised the definition of "Waste." Under the new definition, the term "[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." Prior to the change, these considerations were not included in the definition because "waste" was previously understood to include all nonproduction of oil and gas. The Commission otherwise did not change the definition of "waste," which, among other things, "includes the escape, blowing, or releasing, directly or indirectly into the open air of gas from wells productive of gas only, or gas in an excessive or unreasonable amount from wells producing oil or both oil and gas." C.R.S. § 34-60-103(11)(a).

[1] The Mission Statement Section also clarifies that the nonproduction of oil and gas resulting from a conditional approval or denial authorized by the section does not constitute waste. C.R.S. § 34-60-106(2.5)(b).

- <u>C.R.S. § 34-60-128(3)(b) (habitat stewardship rules)</u>

This section sets forth the habitat stewardship rules the Commission must consider when exercising its authority under the Act. With SB 19-181, the General Assembly modified the mitigation requirements appropriate for permit conditions. Prior to SB 19-181, the Act required the Commission to consult with and obtain the consent of a surface owner about permit provisions of a permit intended to protect wildlife resources. This effectively gave surface owners the ability to determine whether any specific permit condition intended to protect wildlife was permissible, even if the permit condition did not actually involve or impact the surface owner's land. SB 19-181 modified this provision to only require the surface owner's consent for permit conditions intended to impact wildlife that directly impact the surface-owner's land. However, the Commission may also require operators to take actions to address indirect impacts to wildlife, such as off-site compensatory mitigation, that do not implicate the surface owner's land without the surface owner's consent.

Together, these changes overhauled the Commission's authority and dictated sweeping regulatory changes. In addition, SB 19-181 gave the Commission more specific rulemaking authority than is generally considered when assessing an agency's cost benefit analysis by removing considerations of cost-effectiveness and technical feasibility from the Act's Mission Statement Section. *See* C.R.S. § 24-4-107 (an agency's more specific statutory language prevails over the Administrative Procedure Act's general provisions).

Pursuant to SB 19-181, the Commission transitioned from volunteer commissioners to full-time commissioners on July 1, 2020. C.R.S. § 34-60-60-104.3. The Commission is supported by approximately 140 staff members. Staff handles the Commission's day-to-day business. Accordingly, Staff drafted and researched the proposed rules and this Analysis. Because Staff was performing those functions on behalf of the Commission, throughout this Analysis the terms "Staff" and "Commission" can be used interchangeably unless context requires otherwise.

2. **The General Assembly Anticipated Significant Costs For the 800/900/1200 Mission Change Rulemaking**

The General Assembly required the Commission to undertake the 800/900/1200 Mission Change Rulemaking and anticipated that it would result in new costs to the Commission, Staff, and other interested parties. For this reason, the General Assembly authorized additional expenditures by the Department of Natural Resources ("DNR"), including the Commission and Colorado Parks and Wildlife ("CPW"), and the Department of Law to implement SB 19-181. The General Assembly's appropriations included an additional $961,015 and 7.0 FTE for FY 2019–20, and an additional $2,589,431 and 14.0 FTE for FY 2020–21. These amounts are above what was authorized in the State budget during the fiscal year prior to the passage of SB 19-181.

3. **Overview of Analysis Requirements and Methodology Review**

On June 19, 2020, Staff provided notice of the 800/900/1200 Mission Change Rulemaking as required by the Administrative Procedure Act ("APA"). C.R.S. § 24-4-103(3). The notice included changes to the 100-Series, 300-Series alternative location analysis and consultation rules related to wildlife, Rule 529, 800-Series, 900-Series, and 1200-Series of the Commission's Rules. This notice was published in the Colorado Register on July 10, 2020.

Pursuant to the APA, C.R.S. § 24-4-103(2.5)(a), any member of the public can request that the Executive Director of the Colorado Department of Regulatory Agencies ("DORA") direct a state agency to prepare a cost-benefit analysis within five days of the rules being published in the Colorado Register. The APA also allows any member of the public to request that an agency issue a regulatory analysis of a proposed rule at any point up to 15 days prior to a rulemaking hearing. C.R.S. § 24-4-103(4.5)(a).

On July 14, 2020, American Petroleum Institute Colorado ("API") requested a cost-benefit analysis for the Commission's noticed 900 Rules Series. On the same date, West Slope Colorado Oil and Gas Association ("WSCOGA") requested that a cost-benefit analysis and a regulatory analysis for the Commission's noticed 1200 Rules Series. After DORA staff consulted with Commission Staff, the DORA Executive Director determined that these analyses were required. The 800/900/1200 Mission Change Rulemaking was originally noticed to begin on August 24, 2020. However, on July 6, 2020, a Commission Hearing Officer, acting at the request of stakeholders Garfield County and the Western and Rural Local Government Coalition, continued the dates of the 800/900/1200 Mission Change Rulemaking hearing to begin September 28, 2020. On September 10, 2020, the final date originally noticed for the rulemaking hearing, the Commission continued the rulemaking to begin on September 28, 2020.

Prior to, and after notice of the proposed rules, Staff engaged with stakeholders, including requestors API and WSCOGA, in significant discussions concerning the proposed rules. Staff also considered all written position statements (including prehearing statements, and responses) submitted by most of the 95 parties to the rulemaking hearing. Finally, the process of preparing this Analysis has allowed Staff to more comprehensively examine and consider the costs and benefits of the proposed rules and alternatives to the proposed rules. These discussions, written statements, and the process of preparing this Analysis will inform Staff's subsequent revisions to the proposed rules, if any. Staff also expects that some of the proposed rules will be further refined and amended by the Commission during the rulemaking hearing. Accordingly, this Analysis addresses the costs, benefits, and regulatory impacts of the rules noticed on June 19, 2020, rather than any future changes that may be proposed to the rules by Staff or the Commission.

The cost-benefit analysis is due no less than ten days prior to the rulemaking hearing, which will commence on September 28, 2020. Staff timely submitted this Analysis to DORA on September 18, 2020.

Because no party requested a cost-benefit analysis or regulatory analysis of the 800 Series Rules, this Analysis does not address the costs or benefits of the proposed 800 Series Rules.

Cost-Benefit Analysis Requirements – C.R.S. § 24-4-103(2.5)(a)

Staff created the cost-benefit portion of this Analysis while acting in good faith to meet the statutory requirements. *See* C.R.S. § 24-4-103(2.5)(d). These requirements are listed in C.R.S. § 24-4-103(2.5)(a)(I)–(V), and include:

- The reason for the rule or amendment;
- The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competiveness;
- The anticipated costs of the rule or amendment, which shall include the direct costs to the government to administer the rule or amendment and the direct and indirect costs to business and other entities required to comply with the rule or amendment;

- Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and
- At least two alternatives to the proposed rule or amendment that can be identified by the submitting agency or a member of the public, including the costs and benefits of pursuing each of the alternatives identified.

Regulatory Analysis Requirements – C.R.S. § 24-4-103(4.5)

Similarly, Staff created the regulatory portion of this Analysis while acting in good faith to meet the statutory requirements. *See* C.R.S. § 24-4-103(4.5)(d). These requirements are listed in C.R.S. § 24-4-103(4.5)(a)(I)–(VI), and include:

- A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;
- To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;
- The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;
- A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;
- A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule;
- A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule; and
- In addition, each regulatory analysis shall include quantification of the data to the extent practicable and shall take account of both short-term and long-term consequences.

Methodology for Data Collection and Assessment

Over several months, a core group of Staff facilitated the collection and assessment of data necessary to complete this Analysis. Staff conducted both structured and unstructured surveys of subject matter experts ("SMEs") inside and outside the Staff as the primary data collection method. These surveys yielded quantitative and qualitative data, which Staff then evaluated and refined so that the costs and benefits of the proposed rules could be quantitatively estimated or fully characterized. Staff consulted closely with CPW staff who are SMEs in wildlife-related issues.

The data used in the Analysis was required to meet each of the following criteria:

- Each SME possessed the necessary skills to describe costs and benefits;
- The data resulted from unbiased inferences;

- The estimates followed acceptable norms for the oil and gas industry;
- Each SME provided honest and accurate assessments;
- The data was presentable in a complete and easy-to-understand manner; and
- Survey questions fit the extent of the Analysis.

Staff members are divided into seven units: Community Relations, Engineering, Environmental, Compliance, Finance, Hearings, and Permitting and Technical Services. Staff also includes an Orphan Well Program, which is part of the Engineering unit. Acting in good faith to prepare a thorough and thoughtful Analysis, SMEs from each unit and program reviewed relevant rules, accessed Staff data, and provided relevant input. In contributing data to the Analysis, Staff relied on their expertise, gained by both education and experience, as well as historical Commission data, industry data sources, and operator and community stakeholder comments. Collectively, Staff brings hundreds of years of experience in all aspects of the oil and gas industry.

Staff in the Environmental, Engineering, Compliance, and Permitting and Technical Services Units possess an average of 20, 27, 25, and 15 years' professional experience, respectively, in the oil and gas industry, environmental consulting, or regulatory agencies. SMEs who contributed data hold educational degrees including but not limited to MPAs, JDs, and PhDs, and Staff members who assisted in preparing this Analysis hold relevant professional licenses, such as professional engineer, professional geologist, and attorney licensure.

Seven CPW Regional Energy Liaisons and Land Use Specialists served as the SMEs for estimating the benefits and impacts related to these proposed wildlife rules. This group has four to 27 years of professional experience in the oil and gas industry, biological research, legal counsel, law enforcement, and previously as private consultants (environmental, NEPA, public land policy & planning, and mitigation) for clients in the energy, transportation, housing, military, federal, state, and municipal sectors. These SMEs hold complementary educational degrees, including, but not limited to JDs, PhDs, Master's Degrees, and Bachelor's Degrees. Furthermore, these SMEs have diverse yet relevant professional licenses, such as a Certified Wildlife Biologist, Professional Wetland Scientist, Business Leadership Certified, Peace Officer Standards and Training-certified, and as an attorney.

Staff engaged in an iterative survey process to obtain needed data. All information provided for this Analysis was reviewed by the core Staff group consisting of at least three individuals, all of whom were working on the entire Analysis and could ensure consistency in data collection methods and could request clarification and follow up data when necessary. The core team included a Staff economist with more than 20 years of professional experience with regulatory impact analyses, fee and rate studies, and technical evaluation of resource economics matters related to energy, recreation, real estate, and air quality.

Staff ultimately decided to build an easy-to-understand and comprehensive Analysis on the following five basic principles of economic analysis:

1. **Uncertainty**. The Analysis will estimate the costs and benefits for rules that have not yet been promulgated or subject to the complete public rulemaking process, and for those reasons, all these estimates possess varying degrees of uncertainty. By carefully considering relevant issues, Staff has worked to minimize the role of uncertainty in each estimate, but the Analysis can never eliminate uncertainty. Staff does not intend

for this Analysis to be used by any party, or by the Commission itself, to commit funds or other resources, at any time, because actual costs and benefits may be greater or smaller for that party than might be estimated in this Analysis.

2. **Types of Impacts**. Costs and benefits are identified as *one time* or *ongoing*, and the Analysis reports each category of cost or benefit as separate subtotals. No discount rate was required in the analysis, because the impacts are level over time at average industry rates of activity. Ongoing costs can be expected to recur per year into perpetuity. One-time costs are assumed to be incurred entirely within the first year following the effective date of rule changes.
3. **Market Cycles**. Staff accounted for volatility in industry prices and activity during an economic cycle by using longer-term historical data whenever available and projecting impacts that blend peak and trough years in these cycles. In some cases, data averaging over 20 years contributes to estimates in the Analysis that are independent of the multiple boom and bust periods during that timeframe. Staff did not prepare the Analysis with any specific market conditions such as minimum commodity prices in mind.
4. **Statewide Scope**. Similarly, Staff acknowledges that costs and benefits will vary not only over time, but also between operators and geographic locations. Staff prepared this Analysis using weighted averaged data that reflect the full range of operator locations and practices across Colorado's oil and gas basins, as documented by Commission data and SME field experience. Where a rule applied to only a specific geographic area, Staff applied GIS tools or other estimation methods to identify the subset of locations impacted by the rule.
5. **Data Evaluation**. Staff checked all data for consistency and sought to remedy outlier or contradictory sets of economic data before using it in calculations. Staff also remedied gaps found in the survey data by requesting additional data from SMEs. In each instance, Staff relied on SME expertise to determine the best course of action for completing the Analysis.

Economic Assumptions

All estimates in the Analysis follow these conventions:

1. All impacts are estimated and expressed in 2020 dollars or full-time equivalents ("FTEs"), and one FTE is defined as 2080 paid hours per year following Colorado government conventions;
2. The impact on industry from a change in workload for its staff or contractors is assumed to average $150/hour, which is a total compensation figure that includes not only take home pay, but also benefits, employment taxes, employee overhead, and other employee-related indirect costs;
3. Anytime the phrase "cost net of benefit" or "benefit net of cost" is used in summary analysis, the reader should assume that all quantified costs and benefits caused by rule changes have been combined, allowing the total benefit impact to offset the total cost impact;

4. Net industry impacts are represented by increased costs, such as -$1.5 million per year, offset by cost savings (each one is a benefit), such as $0.5 million per year, caused by the proposed rule changes;
5. Net State government staffing impacts are represented by additional staff workload (a cost), such as 0.50 FTE recurring annually, offset by reduced staff workload (each one is a benefit), such as -0.75 FTE recurring annually, caused by rule changes;
6. All time periods are best approximations;
7. A reference to "industry" is a reference to all operators combined; and
8. The costs for industry voluntary compliance with any proposed regulatory standard are not part of the regulatory baseline. That is, a proposed change in any standard will result in quantified costs and benefits in this Analysis even if operators in the past voluntarily met that standard and paid costs or received benefits before the new standards are adopted. Because Staff does not have comprehensive data about voluntary compliance rates, Staff assumed (except where otherwise noted in the Analysis) that no operators were already complying with the new standards adopted in the 800/900/1200 Mission Change Rulemaking. This assumption will cause some degree of overestimation of certain costs or benefits to industry.

By employing this thoughtful and deliberative approach, Staff believes this Analysis is a straight-forward, good faith assessment of expected costs and benefits for the rules associated with the 800/900/1200 Mission Change Rulemaking.

4. **Quantitative vs. Qualitative Costs and Benefits Explained**

This Analysis addresses costs and benefits that are both quantitative and qualitative. Both types of data are amenable to analysis and help illustrate the true costs and benefits of the relevant rules.

Quantitative data is concrete and objective. Such data consists of measures of values or counts and are expressed as numbers. Examples of quantifiable costs include: expenditures to comply with a regulatory change, *i.e.* equipment purchases; the cost and duration of actions required to comply with rule changes, *i.e.*, how many additional groundwater samples will be taken per year; and the number of hours it will take Commission staff to review newly-produced data. Examples of quantitative benefits include reduced Staff hours to review updated form submissions and reduced remediation costs for operators from avoided spills and releases due to improved environmental safeguards. Quantitative data can be collected using scientific principles and can be easily expressed as cause-and-effect relationships. Because of the objective nature of quantitative data, Staff endeavored to identify, collect, and assess this type of data whenever possible for this Analysis.

Qualitative data, while just as meaningful as quantitative data, is more subjective and ambiguous. Intangible costs and benefits do not lend themselves easily to direct and quantitative measures. In other words, these types of attributes do not have readily available standard measurement scales and tend to be subject to great inter individual measurement variability. This data is about categorical variables, or groups of data that are based on similar features. Qualitative data can be collected using more open-ended methods, such as through observation and interviews. Examples of qualitative benefits include increased public confidence in operators and government regulators; improved public health from reduced pollution; and avoided environmental contamination that otherwise might harm ecosystems, crops, soil, and groundwater; and protection of wildlife resources and their habitat.

The distinction between these types of costs and benefits is very important because many of the specific regulatory outcomes that the General Assembly instructed the Commission to achieve through the 800/900/1200 Mission Change rulemaking—protecting public health, safety, welfare, the environment, and wildlife resources—are outcomes that are better assessed qualitatively than quantitatively. However, many of the costs of achieving those statutorily mandated outcomes are monetary costs incurred by operators.

With this in mind, Staff performed both quantitative and qualitative analysis to obtain a complete picture of the 800/900/1200 Mission Change Rulemaking's expected costs and benefits. Collecting and analyzing quantitative data allowed Staff to confirm and test historical trends to assess the costs and benefits of the rules. Collecting and analyzing qualitative data allowed Staff to better understand the scope and full nature of the proposed rules' costs and benefits.

Accordingly, throughout the Analysis, Staff collected both quantified cost and benefit data where possible, and also identified qualitative costs and benefits that cannot be quantified. Although the APA's requirement for a cost-benefit analysis is silent as to whether data must be quantitative or qualitative, this approach is consistent with the APA's analogous requirement that agencies consider both qualitative and quantitative costs and benefits when conducting a regulatory analysis, a similar but distinct form of analysis. *See* C.R.S. § 24-4-103(4.5)(a)(II). Because this Analysis is a combined cost-benefit analysis and regulatory analysis, Staff determined that it was appropriate to consider both qualitative and quantitative data. However, as discussed above, SB 19-181 changed the Commission's Mission and required that the Commission protect public health, safety, welfare, the environment, and wildlife resources without reference to cost-effectiveness. *See* C.R.S. §§ 34-60-102(1); 34-60-103(5.5); 34-60-106(2.5)(a).

RESULTS IN SUMMARY

After the implementation of proposed rules, **Table 1** (below) shows a net cost impact to the industry, communities, and wildlife between \$20.6 and \$31.5 million per year. The Analysis also estimates a one-time net cost impact on industry of \$19.7 to \$55.9 million.

Table 1 – 900 and 1200 Series Rulemaking Full Summary of Impacts

impact	low	high	type
Industry, Communities, and Wildlife			
Cost to Industry	-$30,460,230	-$36,207,030	annual
Benefit to Industry, Communities, and Wildlife	$9,872,820	$4,693,693	annual
Cost Net of Benefit	**-$20,587,410**	**-$31,513,337**	**annual**
Cost to Industry	-$21,432,450	-$55,942,950	one time
Benefit to Industry, Communities, and Wildlife	$1,700,000	$17,000	one time
Cost Net of Benefit	**-$19,732,450**	**-$55,925,950**	**one time**
State Government			
Cost to State Government	6.92	9.11	annual FTE
	4.39	5.36	one time FTE
Benefit to State Government	-1.75	-1.07	annual FTE
	-1.01	-1.01	one time FTE
Cost Net of Benefit	**5.17**	**8.04**	**annual FTE**
	3.38	**4.35**	**one time FTE**
Benefit to State Programs	**-$3,262,000**	**-$7,145,000**	**annual**
Benefit to State Programs	**-$28,500,000**	**-$28,500,000**	**one time**

Notes:

(i) All figures are estimates and expressed in 2020 dollars or FTE.

(ii) The analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.

(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).

(iv) Net staffing reflects additional staff workload (a cost), offset by reduced staff workload (a benefit), caused by rule changes.

(v) A benefit to a State program is a reduction in total expenses during the program lifetime.

The Analysis finds that State agencies will experience a net increase in ongoing workload between 5.17 and 8.04 FTE, and a 3.38 to 4.35 FTE increase in one time staffing need. State Programs, in particular the Commission's Orphaned Well Program, will show a decrease between $3.3 and $7.1 million annually in expenses during the program lifetime (a benefit to the State). This program will also have a one-time reduction of $28.5 million in lifetime program expenses.

It is important to note that the net impacts discussed above and presented in Table 1 below should not be viewed as a definitive description of actual impacts to industry, State Government, or any other party. Additional context is necessary for any conclusions to be drawn about the data in Table 1. In one example, the net quantifiable costs to industry of the 800/900/1200 Mission Change Rulemaking may be contextualized in numerous ways. Net quantifiable costs could be considered on a per-well basis, per-operator basis, or in comparison to the average annual revenue generated by individual wells or for individual operators. For example, distributed across the 51,434 currently active wells in Colorado, the annual net costs to industry of $20.6 and $31.5 million is equivalent to $400 to $613 per well, and one-time impacts to industry of $19.7 to $55.9 million is equivalent to $384 to $1,087 per well.

However, Staff did not deem it appropriate to choose or rely upon any one specific method of contextualizing net quantifiable costs to industry, because ultimately all methods share the same three limitations. First, they are estimates developed the Commission's team of expert staff that are limited by numerous uncertainties, and those uncertainties are compounded in the process of summing costs and benefits into a single dollar value. Second, the net costs and benefits estimated in this Analysis reflect only quantified costs and benefits, and a significant portion of the costs and benefits of the 800/900/1200 Mission Change Rulemaking are not quantifiable, and were therefore analyzed qualitatively.

Finally, as required by the APA, C.R.S. § 24-4-103(2.5), this Analysis addresses the 800/900/1200 Mission Change Rules as initially proposed on June 19, 2020, and does not reflect potential future revisions to those Rules by Staff prior to the rulemaking hearing commencing, or the changes that the Commission will likely make to the proposed Rules during the forthcoming rulemaking hearing. Accordingly, it would be inaccurate, and potentially misleading, for Staff or any other party to draw a firm conclusion about the actual net quantifiable costs of the 800/900/1200 Mission Change Rulemaking to industry (or any other party) due to the limits of this Analysis.

Individual Rule Series Summaries

Oil and gas operations are sophisticated, complex, and have a variety of impacts for each step in the exploration and production processes. For years, the Commission has generally grouped clusters of similar requirements into separate series. However, over the course of numerous rulemakings, some topics were spread over several series. During the 800/900/1200 Mission Change Rulemaking and previous 200–600 Mission Change Rulemaking, Staff has streamlined each rules series and provided a more holistic approach to the specific rule topics. As a result, Staff reduced the duplication of its efforts, eliminated redundant regulatory requirements, and identified the Commission's overall regulatory agenda for each substantive topic. Moreover, by more thoroughly integrating regulatory requirements in each series, Staff expects both greater regulatory understanding by all interested parties as well as reduced compliance costs.

The following is a description of the Rules Series covered by this Analysis:

- **900 Series – Environmental Impact Prevention**

The 900 Series consolidates into one Rules Series prior Commission Rules intended to prevent and remediate environmental impacts. This change will improve clarity for operators, local governments, and the public since previous provisions related to protecting the environment through the management of exploration and production waste were contained in the 300 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 ordering, the 900 Series begins with Rules intended to prevent contamination from occurring and ends with Rules addressing cleanup standards for when contamination nevertheless occurs.

- **1200 Series – Protection of Wildlife Resources**

The 1200 Series revises the Commission's wildlife rules to conform with SB 19-181's mandate to protect public health, safety, welfare, the environment, and wildlife resources. The revisions to the 1200 Series also implement an off-site compensatory mitigation program, including both direct and indirect impacts, consistent with SB 19-181's changes to the Act's habitat stewardship provisions. The updates to the 1200 Series also address SB 19-181's requirements to adopt alternative location analyses and to address potential cumulative impacts of oil and gas development. Staff 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.

Each impact belongs to one of seven impact types, and labels for groups of impacts are provided in the margins of this Analysis. The glossary (below) explains each type.

Glossary of Analysis Impact Labels

section / label in margin	meaning of label
Industry and Community	
($ Cost)	Rule adds to baseline industry costs
($ Benefit)	Rule reduces baseline industry costs
(Qualitative)	Rule has a positive impact on a nonmonetary value in the community
State Government	
(FTE Cost)	Rule adds to State government workload
(FTE Benefit)	Rule reduces State government workload
($ Cost)	Rule adds to State government program total expenses during the program lifetime
($ Benefit)	Rule reduces State government program total expenses during the program lifetime

Note:
(1) These labels are placed in the margin of the Analysis to help the reader better classify and understand the impact detailed by each section of narrative.

900 SERIES: ENVIRONMENTAL IMPACT PREVENTION
DETAILED DESCRIPTION OF COSTS AND BENEFITS

The 900 Series contain the Commission's Rules addressing the prevention of environmental impacts as a result of oil and gas development. The 900 Series fulfills the Commission's statutory duty "to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources" and "protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5). The Rules are designed to prevent environmental contamination from occurring and provide remediation standards when contamination nevertheless occurs.

The passage of SB 19-181 necessitated an update of this Rule Series in order to fully implement the legislation's elevation of protections for public health, safety, welfare, the environment, and wildlife resources. C.R.S. § 34-60-106(2.5)(a). In order to comply with SB 19-181's revised statutory directive, the Staff have proposed several revisions to defined terms in the 100 Series. For example, Staff has updated "Pollution" primarily to refine 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. Staff has also updated several 900 Series Rules to provide the Director and Commission with the discretion to take certain actions to protect public health, safety, welfare, the environment, and wildlife resources.

Staff determined that all the costs and benefits estimated and described below, considered separately or combined, will have no measurable impacts on job creation or the economy because many of the items that will incur costs will be absorbed by current employees. In addition, Staff believes that the proposed changes to the 900 Series were the least costly way for the Commission to effectively comply with the General Assembly's mandates in SB 19-181. Staff also believes that, despite the additional net cost imposed on industry, the importance of the short- and long-term qualitative benefits to the industry and community warrant the changes to the 900 Series because of the protections the rules provide to public health, safety, welfare, the environment, and wildlife resources.

RULES FOR WHICH COSTS AND BENEFITS ARE IMPLICATED

Table 2 (below) compiles all quantified costs and benefits to industry and the community that are expected after the 900 Series Rules are implemented. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series. Staff expect a wide spectrum of impacts to industry on a per rule basis, from an annual benefit of $5.0 million to an annual cost of $23.8 million. There are also a range of one-time impacts that range from a $1.7 million benefit to a $25.0 million cost to industry.

Table 2 – 900 Series Industry and Community Impact Detail

rule	impact	low	high	type
901.a	Cost to Industry	-$200	-$1,000	annual
901.a	Cost to Industry	-$12,000	-$60,000	annual

903.d.(3)	Benefit to Industry	$3,913,443	$5,031,570	annual
903.b.(3) & 903.d.(5)	Cost to Industry	-$1,858,500	-$2,818,000	one time
903.c.(2).C	Cost to Industry	-$375	-$1,125	annual
903.d.(4).B	Cost to Industry	-$134,650	-$134,650	annual
903.d.(6).A	Cost to Industry	-$810,000	-$10,750,000	one time
903.d.(6).C	Cost to Industry	-$402,750	-$2,013,750	one time
903.d.(6).C	Cost to Industry	-$150	-$3,750	annual
905.c(5)	Cost to Industry	-$11,000	-$11,000	annual
905.g	Cost to Industry	-$15,330	-$15,330	annual
907.b (6)	Cost to Industry	-$800,000	-$800,000	annual
907 (7)	Cost to Industry	-$12,000	-$12,000	annual
908.a (3)	Cost to Industry	-$20,000	-$20,000	annual
908.c (2)	Cost to Industry	-$8,000	-$8,000	annual
909.a (2) and (3)	Cost to Industry	-$8,556,000	-$8,556,000	one time
909.j (1)-(5)	Cost to Industry	-$5,371,200	-$5,371,200	one time
909.j.(1)-(5)	Cost to Industry	-$330,000	-$330,000	annual
910.a.	Cost to Industry	-$200,000	-$500,000	annual
910.a.	Benefit to Industry	$100,000	$500,000	annual
910.b.	Cost to Industry	-$3,000,000	-$25,000,000	one time
910.f.	Cost to Industry	-$1,000	-$2,500,000	annual
910.f.	Benefit to Industry	$1,000	$3,000,000	annual
911.a	Cost to Industry	-$50,000	-$50,000	annual
911.a (4)	Cost to Industry	-$23,750,000	-$23,750,000	annual
912.a (5)	Cost to Industry	-$50,000	-$50,000	annual
912.b.(1)	Cost to Industry	-$92,500	-$231,250	annual
912.b (4)	Cost to Industry	-$36,750	-$36,750	annual
912.b (6)	Cost to Industry	-$37,500	-$37,500	annual
912.b (10)	Cost to Industry	-$2,500	-$2,500	annual
912.f	Cost to Industry	-$40,725	-$40,725	annual
913.c (9)	Cost to Industry	-$1,916,000	-$1,916,000	annual
913.e (2)	Cost to Industry	-$1,400,000	-$1,400,000	one time
913.e (3)	Cost to Industry	-$125,000	-$125,000	annual
915.a.	Cost to Industry	-$171,000	-$171,000	annual

915.b.	Cost to Industry	-$120,000	-$120,000	annual
915.b.	Benefit to Industry	$8,000	$670,000	annual
915.c.	Cost to Industry	-$770,000	-$770,000	annual
915.e.(3)B	Cost to Industry	-$200,000	-$1,000,000	annual
915.e.(3)C	Cost to Industry	-$3,750	-$3,750	annual
915.e.(3)C	Benefit to Industry	$11,250	$11,250	annual
915.e.(4)	Cost to Industry	-$15,000	-$15,000	annual
915.f.	Cost to Industry	-$34,000	-$34,000	one time
915.f.	Benefit to Industry	$17,000	$1,700,000	one time

Notes:
(i) All figures are estimates and expressed in 2020 dollars or FTE.
(ii) The analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).

Table 3 (below) details all quantifiable impacts on State Government from implementation of the 900 Series Rules. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series. Staff expect a wide spectrum of workload impacts on a per rule basis, from a 0.72 FTE benefit or reduction in ongoing State agency staffing to a 1.82 FTE cost or increase in ongoing State agency staffing.

There are smaller one-time workload impacts between a 0.72 FTE reduction in State agency staffing to a 2.74 FTE increase in State agency staffing. Finally, there are significant benefits or reductions in lifetime total State agency program costs between $42,000 and $5.0 million annually, and there is also a $28.5 million one-time reduction in lifetime total State agency program costs.

Table 3 – 900 Series State Government Impact Detail

Rule	impact	low	high	type
901.a	Cost to State Government	0.001	0.005	annual FTE
901.a	Cost to State Government	0.016	0.079	annual FTE
903.b.(1) & (2), 903.c.(2), 903.d.(1) & (3)	Benefit to State Government	-0.024	-0.123	annual FTE
903.c.(2).C	Cost to State Government	0.001	0.004	annual FTE
903.d.(6).C	Cost to State Government	0.323	1.291	one time FTE

903.d.(6).C	Cost to State Government	0.000	0.002	annual FTE
905.c(5)	Cost to State Government	0.096	0.096	annual FTE
905.d (1) - (3) B - ff.	Benefit to State Government	-0.096	-0.096	annual FTE
905.e . (1) - (2).through g	Benefit to State Government	-0.120	-0.192	annual FTE
905.g	Cost to State Government	0.103	0.103	annual FTE
907.b (6)	Cost to State Government	0.120	0.120	annual FTE
907 (7)	Cost to State Government	0.077	0.077	annual FTE
907 (7)	Benefit to State Government	-0.015	-0.015	annual FTE
908.a (3)	Cost to State Government	0.010	0.010	annual FTE
908.a (3)	Benefit to State Government	-0.001	-0.001	annual FTE
908.c (2)	Cost to State Government	0.004	0.004	annual FTE
909.a (2) and (3)	Cost to State Government	2.742	2.742	one time FTE
909.a (2) and (3)	Cost to State Government	0.005	0.005	annual FTE
909.a (2) and (3)	Benefit to State Government	-$28,500,000	-$28,500,000	one time
909.a (2) and (3)	Benefit to State Government	-0.240	-0.240	one time FTE
909.j (1)-(5)	Cost to State Government	0.807	0.807	one time FTE
909.j (1)-(5)	Cost to State Government	0.026	0.026	annual FTE
909.j.(1)-(5)	Benefit to State Government	-0.048	-0.048	annual FTE
910.a.	Cost to State Government	0.017	0.017	annual FTE
910.a.	Benefit to State Government	-0.019	-0.019	annual FTE
910.b.	Cost to State Government	0.168	0.168	one time FTE
910.b.	Benefit to State Government	-0.721	-0.721	one time FTE
910.f.	Cost to State Government	0.010	0.096	annual FTE
910.f.	Benefit to State Government	-0.014	-0.144	annual FTE
911.a	Cost to State Government	0.019	0.019	annual FTE
911.a (4)	Cost to State Government	1.599	1.599	annual FTE
911.a (4)	Benefit to State Government	-$1,250,000	-$5,000,000	annual
912.a (5)	Cost to State Government	0.024	0.024	annual FTE
912.b.(1)	Cost to State Government	0.077	0.077	annual FTE
912.b.(1)	Benefit to State Government	-0.038	-0.038	annual FTE
912.b (4)	Cost to State Government	0.053	0.053	annual FTE
912.b (4)	Benefit to State Government	-0.053	-0.053	annual FTE
912.b (6)	Cost to State Government	0.018	0.018	annual FTE

912.b (6)	Benefit to State Government	-0.012	-0.012	annual FTE
912.b (10)	Benefit to State Government	-0.012	-0.012	annual FTE
912.e (2)	Benefit to State Government	-0.048	-0.048	annual FTE
912.f	Cost to State Government	0.044	0.044	annual FTE
912.f	Benefit to State Government	-0.174	-0.174	annual FTE
913.b.(5)	Benefit to State Government	-0.096	-0.144	annual FTE
913.c (9)	Cost to State Government	1.842	1.842	annual FTE
913.c (9)	Benefit to State Government	-$1,920,000	-$1,920,000	annual
913.e (2)	Cost to State Government	0.337	0.337	one time FTE
913.e (2)	Benefit to State Government	-0.048	-0.048	one time FTE
913.e (3)	Cost to State Government	0.180	0.180	annual FTE
913.e (3)	Benefit to State Government	-0.038	-0.038	annual FTE
913.e (3)	Benefit to State Government	-$42,000	-$175,000	annual
915.a.	Cost to State Government	0.066	0.066	annual FTE
915.b.	Cost to State Government	0.096	0.096	annual FTE
915.b.	Benefit to State Government	-0.014	-0.014	annual FTE
915.c.	Cost to State Government	0.176	0.176	annual FTE
915.e.(3)B	Cost to State Government	0.038	0.038	annual FTE
915.e.(3)B	Benefit to State Government	-$50,000	-$50,000	annual
915.e.(3)C	Cost to State Government	0.005	0.005	annual FTE
915.e.(4)	Cost to State Government	0.024	0.024	annual FTE
915.f.	Cost to State Government	0.017	0.017	one time FTE
Table 915-1	Benefit to State Government	-0.168	-0.168	annual FTE

Notes:
(i) All figures are estimates and expressed in 2020 dollars or FTE.
(ii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).
(iii) Net staffing reflects additional staff workload (cost impact), offset by reduced staff workload (benefit impact), caused by rule changes.

Table 4 (below) summarizes all quantified impacts to all parties from implementation of changes to the 900 Series Rules. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series.

Overall impacts to industry show annual costs net of benefits between $19.7 and $28.7 million. Industry will also bear one-time costs net of benefits that range between $19.7 and $55.9 million. Overall impacts to State Government indicate ongoing costs net of benefits (workload increases) between 3.41 and 3.92 FTE and smaller one-time costs net of benefits (workload increases) between 3.38 and 4.35 FTE.

State agency lifetime program expenses, largely achieved by avoiding a greater flow of projects into the Commission's Orphaned Well Program, will benefit by an amount that ranges between $3.3 and $7.1 million annually, and by an estimated one-time amount of $28.5 million.

Table 4 – 900 Series Summary of Impacts

Impact	low	High	type
Industry and Community			
Cost to Industry	-$28,925,430	-$32,716,330	annual
Benefit to Industry	$9,212,820	$4,033,693	annual
Cost Net of Benefit	**-$19,712,610**	**-$28,682,637**	**annual**
Cost to Industry	-$21,432,450	-$55,942,950	one time
Benefit to Industry	$1,700,000	$17,000	one time
Cost Net of Benefit	**-$19,732,450**	**-$55,925,950**	**one time**
State Government			
Cost to State Government	4.75	4.91	annual FTE
	4.39	5.36	one time FTE
Benefit to State Government	-1.34	-0.99	annual FTE
	-1.01	-1.01	one time FTE
Cost Net of Benefit	**3.41**	**3.92**	**annual FTE**
	3.38	**4.35**	**one time FTE**
Benefit to State Programs	**-$3,262,000**	**-$7,145,000**	**annual**
Benefit to State Programs	**-$28,500,000**	**-$28,500,000**	**one time**

Notes:

(i) All figures are estimates and expressed in 2020 dollars or FTE.

(ii) The analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.

(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).

(iv) Net staffing reflects additional staff workload (a cost), offset by reduced staff workload (a benefit), caused by rule changes.

(v) A benefit to a State program is a reduction in total expenses during the program lifetime.

DISCUSSION OF RULES

901 – General Standards

Staff amended prior Rule 901, which introduced the Commission's exploration and production ("E&P") waste management rules, primarily to remove duplications found in the Commission's 200 Series General Provisions or clarify certain provisions in more specific rules. Notably, Staff moved prior Rule 901.c to Rule 901.a and revised the rule to comport with SB 19-181's changes to the Commission's statutory authority and mission. Rule 901.a now covers impacts to additional environmental media and a broader range of responsive actions by operators. Rule 901.a also authorizes the Director to act in response to any imminent impact or threatened impact to public health, safety, welfare, the environment, or wildlife resources, which aligns more closely with the Commission's statutory authority under SB 19-181. Rule 901.b is a new rule, but does not implicate any costs or benefits as it incorporates by reference several codes, standards, guidelines, and rules of federal agencies, other state agencies, and nationally recognized organizations and associations. These codes, standards, guidelines, and rules are referenced elsewhere in the 900 Series. Any cost an operator may incur, or benefit it may receive, as a result of compliance is discussed and reflected in the analysis of that specific Rule.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 901 will result in two costs to operators. First, the provisions of Rule 901.a authorize the Director to require an operator to submit a Form 27, Site Investigation and Remediation Workplan, whenever the Director has reasonable cause to believe that the operator has acted in a way that impacts or threatens to impact public health, safety, welfare, the environment, or wildlife resources. The submission of a Form 27 becomes necessary only when the Director requires an operator to suspend operations or initiate immediate mitigation measures. Staff estimates that this type of situation will happen very rarely, at approximately one to five locations per year. Operators will likely spend approximately one hour and 20 minutes preparing each form, with an annual cost to industry between $200 and $1,000.

Second, Rule 901.a also contemplates procedural due process protections for operators subject to discretionary action by the Director. This requirement was expanded to provide additional specificity and a more detailed procedure than current Rule 901.c. The rule also specifies that unlike most hearing matters, the appeal of the Director's decision will bypass an Administrative Law Judge or Hearing Officer and be heard at the next regularly scheduled Commission meeting. By expediting the appeal process by removing an intermediate appellate step, operators may receive a final decision from the agency sooner if they choose to appeal the Director's decision. Staff again estimates that this type of situation will happen very rarely, at approximately one to five locations per year. Operators will likely spend 80 hours preparing for and participating in the expedited hearing process, at a cost to industry of between $12,000 to $60,000 annually.

(Qualitative) Rule 901 will result in qualitative benefits to the community. As identified in the previous paragraph, Rule 901.a authorizes the Director to require the submission of a Form 27 under certain circumstances. Staff expects that as a result of these submissions, public health and environmental quality will be better protected when the Director acts immediately to require operators to address the threat or potential threat to public health, safety, welfare, the environment, or wildlife resources.

- **Impacts on State Government**

(FTE Cost) Staff anticipates that Rule 901.a will increase its workload in two ways. First, Staff expects to process between one and five additional remediation project submissions per year and that it will spend approximately two hours per Form 27. This is likely to result in an annual cost of Staff between 0.0010 and 0.0048 FTE. Staff also assumes it will spend additional time preparing for and participating in the expedited hearing process provided for under Rule 901.a. As indicated above, Staff assumes that this type of situation will happen very rarely and apply to one to five locations per year. Staff estimates that for each hearing, its workload will increase by approximately 33 hours, resulting in an annual increase in workload of 0.016 to 0.079 FTE.

(FTE Benefit) Staff did not identify any FTE benefits associated with Rule 901.

<u>Rule 902 – Pollution</u>

The Commission revised Rule 902, adding in portions of prior Rule 324A and making other changes to the 100 Series definition of "Pollution" to comport with the Commission's mandate under SB 19-181 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 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).

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 902 will result in costs to industry. Rule 902.a requires operators to prevent pollution. The revised rule contemplates that operators will take affirmative steps to stop pollution from occurring. "Pollution," as it is now defined in the 100 Series, means "anthropogenic contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resource that is not authorized by the Commission's Rules" or any other applicable regulations. In addition, Rule 902.b requires operators to prevent adverse environmental impacts that result from oil and gas operations, and protect and minimize impacts to public health, safety, welfare, the environment, and wildlife resources. Staff's decades of experience with enforcing prior Rule 324A confirm the importance of having enforceable regulatory standards to address forms of pollution that are forbidden by the Act but not otherwise addressed in the Commission's Rules. These changes were also necessary in order to meet the statutory requirements of SB 19-181, and to specifically fulfill the Commission's obligation to regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts. See C.R.S. § 34-60-106(2.5)(a). As a result, Staff anticipates that operators may incur additional enforcement costs annually if more enforcement actions are pursued under Rule 902. However, the frequency of these types of actions is difficult to quantify and Staff does not have data available to estimate the amount of this annual cost to industry.

(Qualitative) Rule 902 will result in qualitative benefits to the community. Because Rule 902 reflects the Commission's statutory directive to "protect against adverse environmental impacts on any air, water, soil, or biological resources resulting from oil and gas operations," C.R.S. § 34-60-106(2.5)(a), the community will likely see additional environmental remediation and experience fewer environmental impacts as operators act to prevent pollution and prevent adverse environmental impacts. Enforcement of the rule will also positively affect public health outcomes associated with pollution.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur a cost associated with Rule 902. As a result of the rule's updated directives to prevent pollution and prevent adverse environmental impacts, Staff anticipates that additional enforcement proceedings could be initiated. Some of those enforcement matters may require more resources to prosecute as Staff and industry navigate the contours of the new rule. Because it is difficult to project with certainty the amount of enforcement actions the Commission may pursue in a year, Staff does not have data to estimate the amount of annual FTE cost to the agency.

(FTE Benefit) Staff did not identify any FTE benefit associated with Rule 902.

Rule 903 – Venting or Flaring Natural Gas

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 Commission has statutory authority to regulate venting and flaring of natural gas for five main reasons: (1) venting and flaring are each an integral component of oil and gas operations, and the Commission has broad authority over such operations; (2) the unintentional combustion of vented gas and fires caused by improper flaring of gas implicate safety risks; (3) odors caused by venting natural gas impact public welfare; (4) there are public health impacts associated with emitting natural gas into the air and combusting it onsite; and (5) the venting and flaring of gas constitute waste of natural gas. Although the Commission has the authority to regulate activities that are also regulated by the Colorado Air Quality Control Commission ("AQCC"), the Commission has 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.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 903 will result in various costs to industry. Pursuant to Rule 903.a.(2), operators must immediately provide verbal, written, or electronic notice to relevant and proximate local governments and, if applicable, local emergency responders in the event of venting or flaring due to an upset condition. Staff combined and updated prior Rules 317.p and 912.e which both required notice of a flaring event to local emergency dispatchers, but lacked specificity. This Rule is intended to ensure that local emergency response agencies have the information they need to respond to emergency calls related to flaring events. Since venting may have public health and safety impacts, Staff added venting to the list of activities requiring notice because it is important for local governments and emergency response agencies to also be informed of planned and unplanned venting events. Staff anticipates that this updated notification requirement will require operators to spend about 0.25 hours per notification annually. However, because it is difficult to estimate how many locations will experience unplanned venting or flaring in a year, Staff does not have sufficient data to quantify the annual cost to industry.

Next, Rules 903.b.(1) and (2), 903.c.(2), and 903.d.(1) and (3) concern venting and flaring activities at new and existing wells during drilling, completion, and production operations. Rules 903.b.(1) and (2) require operators to capture or combust gas escaping from wells during drilling operations using the best available technology and, if doing so would pose safety risks to onsite personnel, operators may obtain the Director's approval to vent by submitting a Form 4, Sundry Notice. Rule 903.c.(2) provides that operators may flare gas during completion operations with written approval from the Director and only under certain listed circumstances. And Rules 903.d.(1) and (3) prohibit venting and flaring of natural gas from new and existing completed wells, respectively, after the commencement of production operations except under certain numerated exceptions. Rules 903.d.(1) and (3) also provide reporting and approval requirements for ongoing venting and flaring. Rules 903.b.(1) and (2), 903.c.(2), and 903.d.(1) will apply to all new oil and gas wells, statewide. Staff estimates that Rule 903.d.(3) will likely apply at 175 to 200 wells statewide that currently flare gas, and result in ongoing costs for these wells.

Operators may comply with these Rules in a number of ways. For example, operators may expend resources building pipeline infrastructure to connect to wells so that they can capture gas that otherwise would have been no longer have vented or flared. Alternatively, operators may also invest in other systems for using gas beneficially on site. An operator's chosen method of compliance will vary widely depending on a number of factors. Operators presumably have pipeline infrastructure available for gas wells, while operators are more likely to incur costs to capture or beneficially use gas onsite for oil wells that co-produce natural gas. For new wells, advance planning through gas gathering plans required by Rule 903.e may facilitate more of the wells connecting to gathering line infrastructure, whereas for existing wells, connection to a gathering system may be more complex, and it may be more likely that operators will choose to use gas beneficially for other uses on site. Additionally, a well's proximity to gathering line infrastructure will likely be a key factor in an operator's choice of compliance methods, but Staff does not have granular data about the proximity of new and existing wells to pipeline infrastructure that would be required to make estimates. The availability of gas gathering infrastructure varies widely between basins and fields across the state, with natural gas and coalbed methane fields such as the Piceance, San Juan, and Raton Basins having relatively prevalent pipeline infrastructure, to highly-developed oil fields like the Denver-Julesburg Basin with fairly prevalent pipeline infrastructure, to less-developed oil fields like the North Park Basin with less or not-yet developed pipeline infrastructure.

While some of these options could be quite costly in some circumstances, and the Commission does not intend to overlook those costs in this analysis, Staff does not have sufficient data to estimate the monetary impact to industry. This is largely because the Rules do not require operators to choose any one way of capturing and beneficially using gas instead of venting or flaring it, rendering any quantified estimate of costs impossible for the reasons discussed above. **Table 5** (below) provides available quantitative data about selected portions of these considerations in additional detail. However, it is important to emphasize that by assessing many of the costs associated with Rule 903 qualitatively, the Commission does not intend for stakeholders or the public to consider that costs to industry will be non-existing—but rather that for the reasons discussed above, Staff is unable to quantify them in this Analysis.

Rules 903.b.(3) and 903.d.(5) contain the general requirements for the use of enclosed combustors during oil and gas drilling and production operations at new and existing oil and gas locations, respectively. Under Rule 903.b.(3), operators are required to use enclosed combustors and locate them a minimum of 100 feet from the nearest surface hole location during drilling operations. These specifications standardizing the type and location of combustors that may be used during the drilling process are intended to provide clarity to operators and promote safety at oil and gas locations. Rule 903.d.(5) applies to all new and existing oil and gas wells that are in the production phase, and requires each enclosed combustor to be equipped with an auto-igniter or continuous pilot light, and have a design destruction efficiency of at least 98% for hydrocarbons. The requirement of an auto-igniter or continuous pilot light is an important safety precaution to protect public safety and prevent unintentional wildfires set by malfunctioning unenclosed flares. Similarly, the destruction efficiency specifications better align with AQCC regulations governing destruction efficiency for emissions control devices. Staff estimates that operators will have to retrofit combustion equipment at approximately 175 to 200 well locations that were constructed prior to 2015. Prior Rule 912.d set a less-specific standard for combustor enclosure, and Staff's experience in the field indicates that most operators have already installed enclosed combustors. Based on available information, Staff assumes that operators will spend between $10,620 and $14,090 per well to update combustor technology. This results in an annual cost to industry between $1,858,500 and $2,818,000. **Table 5** (below) provides these calculations in additional detail.

Table 5 – Impact Calculation Detail for Rules 903.b.(1) (2) & (3), 903.c.(2), 903.d.(1) (3) & (5)

impact scenario / item	unit	low value	high value
INDUSTRY BENEFIT (1)			
Gas Flared in Colorado, 2000-2020 Average	MCF/year	2,640,000	2,640,000
Share of Flared Gas Reduced by New Rules	percent	70%	90%
First Quarter 2021 NYMEX Henry Hub Price	($/MMBTU)	$2.16	$2.16
Conversion MMTB to MCF	(MCF/MMBTU)	0.9804	0.9804
Subtotal, Total Benefit	**2020$ per year**	**$3,913,443**	**$5,031,570**
INDUSTRY COSTS (2)			
Shift to Enclosed Combustors			
Number of Wells on a Prototype Wellpad	wells	10	10
Capital Cost Increase per Wellpad Under New Rules	2020$ / wellpad	$105,000	$140,000
Labor Cost Increase per Wellpad Under New Rules	2020$ / wellpad	$1,200	$900
Total Cost Difference per Well Under New Rules	2020$ / well	$10,620	$14,090
Total Wells Adopting Enclosed Combustor Technology	per year	175	200
Subtotal, Total Cost for Enclosed Combustors	**2020$ per year**	**$1,858,500**	**$2,818,000**
Existing Wells No Longer Flaring Pursuant to Rule 903.d.(3) by Connecting to Sales Line Infrastructure			
Wells Flaring Gas Without a Filed Sundry	per year	1,985	1,985
Wells Flaring Gas With a Filed Sundry	per year	62	62
Total Wells Flaring Gas, 2000-2020 Average	**per year**	**2,047**	**2,047**
Share of Wells No Longer Flaring Because of New Rules	percent	70%	90%
Wells No Longer Flaring Gas Because of New Rules	per year	1,433	1,842
Cost Per Well to Extend Gathering Line Infrastructure or Otherwise Capture Gas, Average	2020$ / well	unknown	unknown
Subtotal, Total Cost for Infrastructure	**2020$ per year**	**unknown**	**unknown**

Pursuant to Rule 903.c.(2).C, operators may flare gas during completion operations with specific written approval from the Director under an enumerated list of circumstances. Subsection C specifies that an operator may direct gas to an emission control device and combust the gas in order to protect the safety of onsite personnel during upset conditions. However, if this flaring period exceeds 24 hours, an operator must obtain the Director's approval to continue flaring and, within seven days of the flaring event, submit a Form 4 to report the upset condition and estimate the volume of gas flared. Staff 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. Staff assumes that operators will submit between 10 and 30 Form 4s as a result of the Rule's reporting requirement and that it will require 15 minutes of time to complete each form. This results in an annual cost to industry between $375 and $1,125.

Rule 903.d.(4).B applies to emissions during production and requires operators to notify all mineral owners of the volume of oil and gas that is vented, flared, or used on-lease. This expanded reporting requirement requires operators to maintain records of this notice and provide it to the Director upon request. This Rule is intended to provide operators with an additional incentive to avoid waste and capture gas or put it to a beneficial use. Staff assumes that the requirement to report the volume of wasted gas to mineral owners will impact operators at approximately 10,772 wells. Staff estimates it will cost operators five minutes per well to meet the notification requirements, resulting in a total annual cost of $134,650.

Under Rule 903.d.(6).A, pits with uncontrolled actual volatile organic compound ("VOC") emissions of greater than two tons per year cannot be located within 2,000 feet of a building or designated outside activity area. This regulatory change is intended to apply retroactively. The permissible VOC emissions from pits was reduced from five tons per year to two tons per year in order to comport with SB 19-181's changes to the Commission's mission and statutory authority to protect public health. Staff determined that stronger protections from these existing pits are necessary for public health, 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. Operators who fall under this equipment standard will incur costs to enclose or close existing pits if they are too close to a building. Staff estimates this requirement will apply to between 27 and 43 pits, or 1–2% of pits statewide, and cost between $30,000 and $250,000 per pit. This results in a total one-time cost of between $810,000 and $10,750,000.

There are two costs to operators associated with Rule 903.d.(6).C. First, the Rule requires operators to submit the basis for their determination of applicability of Rule 903.d.(6) on a Form 4 within one year for existing pits. Staff currently has limited information available to ensure compliance with the prior rule governing emissions from pits, and operators submitting applicability determinations will provide Staff with the information necessary to better identify pit emissions levels and enforce Rule 903.d.(6). As a result of this Rule, operators of the approximately 2,685 pits in existence statewide that fall under these requirements will be required to submit a Form 4 one time. Staff estimates operators will spend between one and five hours preparing each form, resulting in a total one-time cost between $402,750 and $2,013,750.

Rule 903.d.(6).C also requires operators to submit the basis for their determination of applicability of Rule 903.d.(6) on a Form 15 for any new pits constructed. For new pits, Staff anticipates that the analysis of dissolved and entrained VOCs in produced water source analyses will provide a reasonable indication of emission rates. However, Staff may consider requiring conditions of approval to monitor and model actual pit emissions on a case-by-case basis as appropriate in order to ensure compliance with this Rule. Staff assumes that operators will spend between one and five hours per Form 4 to provide the requested documentation for any new pit located within 2,000 feet of a building unit. Staff estimates this Rule will apply to between one and five new pits per year, resulting in an annual cost to industry between $150 and $3,750.

Rule 903.e is one of the most important Rules in the 900 Series. It adopts best practices from other states, including North Dakota and New Mexico, of requiring operators to submit gas capture plans as part of their permit applications for new oil and gas locations. Rule 903.e requires operators to conduct up front planning about how they will avoid venting and flaring gas at new locations, and for Staff to work with the operator through the permitting process to identify and facilitate appropriate practices for connecting to a gathering line, using gas beneficially on-site, or other options for gas capture. Gas capture plans will be submitted as an attachment to Form 2A, Oil and Gas Location Assessment applications pursuant to Rule 304.c.(12). Accordingly, Staff did not analyze the costs and benefits of operators completing and staff reviewing gas capture plans, because staff analyzed those costs and benefits in the 200–600 Series Cost-Benefit Analysis.

($ Benefit)

Under Rules 903.b.(1) and (2), 903.c.(2), 903.d.(1) and (3), operators will see monetary benefits if they sell their additional captured natural gas on the market instead of flaring it or venting it. According to Staff's review of Form 4s that have reported the volume of gas flared at existing wells over the past 20 years, an average of 2.64 million Mcf of natural gas is flared at existing wells annually in Colorado. Staff estimates that 70% to 90% of the gas flared from existing wells statewide will be captured each year under Rule 903.d.(3). Based on the methods in the AQCC's economic impact analysis for a rulemaking the agency is currently conducting to implement other parts of SB 19-181,[2] Staff estimates that this gas will be sold at an estimated price of $2.16/Mcf. Accordingly, Staff anticipates that operators will see a benefit between $3,913,443 and $5,031,570 per year from Rule 903.d.(3). **Table 5** (above) provides these calculations in additional detail.

(Qualitative)

Rule 903.a.(2) will decrease the amount of time local governments and local emergency response agencies spend responding to questions about flaring and venting events because each entity will be informed very soon after events occur. As a result, fewer deployments of local fire response agencies may occur, which can result in significant cost savings to local fire departments and conserve resources for other community emergencies. These benefits will be both short- and long-term.

Next, Rule 903.a.(3) allows proximate and relevant local governments and local emergency response authorities to waive their right to notice of flaring or venting due to upset conditions. If local entities choose to waive these notices, it may save them time and money

[2] *See* Air Quality Control Commission, Colo. Dep't of Pub. Health & Env't, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7 (Sept. 4, 2020), *available at* https://drive.google.com/drive/u/3/folders/1TyoffeeZQ2JUbBJPasuHIoEzENO0ORjr

otherwise spent processing such notices. This waiver provision may also benefit operators because they will be excused from providing venting and flaring notices to those local governments and local emergency response authorities that have chosen to waive them, saving operators time and effort over the course of the year. These benefits to local governments and operators will be both short- and long-term.

As a result of the venting and flaring requirements in Rules 903.b.(1) and (2), 903.c.(2), 903.d.(1) and (3), Staff assumes there will be improvements to overall public health and welfare. Staff anticipates that the implementation of these Rules will significantly reduce emissions that contribute to global climate changes, regional ozone formation, and direct health impacts from exposure to hazardous air pollutants. These benefits will be both short- and long-term, but Staff has insufficient data about emissions reductions to estimate total emissions reductions as a result of the rules. Nor does Staff have sufficient data to quantitatively link those emissions reductions to specific monetary metrics of climate or health benefits.

The use of enclosed combustion devices with certain specifications at a standardized distance from wells as required under Rules 903.b.(3) and 903.d.(5) will also positively impact public safety as potential fires will be avoided. Enclosed combustion will be especially valuable for preventing wildfires in remote areas where flaring occurs where wind may cause flame from unenclosed flare to escape and alight surrounding vegetation. While it is impossible to estimate how frequently fires are avoided or the total damage that might be caused by each hypothetical fire, these public safety benefits will be both short- and long-term.

As a result of Rule 903.d.(4).B, mineral owners will benefit by learning what volume of their gas is being wasted each year. This may result in more equitable negotiating positions and lead mineral owners to work with operators in the future to recoup the value of gas that would otherwise be vented or flared. This benefit will be both short- and long-term

Finally, Staff anticipates that Rule 903.d.(6).A will result in one-time public health benefits at the 27 to 43 pits that will have to close or be enclosed to meet the new emissions requirements. By retrofitting these existing pits to meet the VOC emission limit of two tons per year, a significant source of the emissions most likely to cause acute and chronic health problems from locations close to homes will be reduced substantially. However, Staff has insufficient data about current pit emissions rates to quantitatively link those emissions reductions to specific monetary metrics of health benefits.

- **Impacts on State Government**

(FTE Cost)

Staff assumes it will incur costs associated with Rule 903. Due to the reporting requirement for upset conditions contained in Rule 903.c.(2).C, Staff will likely process between 10 and 30 additional Form 4s per year. Staff estimates that 15 minutes will be spent reviewing each Form 4, resulting in an annual cost between 0.001 and 0.004 FTE.

Next, the implementation of Rule 903.d.(6).C will require Staff to review Form 4s submitted by operators to understand how emissions were calculated from existing pits. This cost will apply to 2,685 pits one time and require between 0.25 hours and one hour to review each form. This results in a one-time FTE cost between 0.323 and 1.291 FTE.

Finally, Rule 903.d.(6).C will also result in an annual FTE cost. Because of this Rule, Staff anticipates it will review between one and five Form 15s to understand how operators will calculate emissions from new pits. Staff estimates this process will take between 0.25 hours and one hour per form, resulting in an annual cost between 0.000 and 0.002 FTE.

(FTE Benefit) Rule 903 will likely result in a benefit to Staff. As a result of Rules 903.d.(1) and (3), Staff will process fewer Form 4s requesting permission to vent or flare each year. This will constitute a decrease from the workload typically expended annually on processing Form 4s. Staff assumes that between fifteen and 60 minutes will be saved per Form 4 and that this will impact 70% to 90% of the 285 Form 4s typically submitted for flaring notification annually. This results in an ongoing benefit to Staff of 0.024 to 0.123 FTE per year.

Rule 904 – Evaluating Cumulative Air Emissions Impacts

Rule 904 was adopted to implement the Commission's obligation under SB 19-181 to evaluate cumulative impacts of oil and gas development. In consultation with the Colorado Department of Public Health and Environment ("CDPHE"), the Commission determined that further evaluation of cumulative air and climate impacts of oil and gas development would be valuable to both agencies. While there is a great deal of information currently available on the air and climate impacts of oil and gas development in Colorado, Staff believes that additional studies and further evaluation is necessary to determine whether to adopt appropriately tailored regulations to address these impacts in the future.

- **Impacts on Industry and the Community**

($ Cost) Staff anticipates that industry may incur costs associated with Rule 904. Pursuant to Rule 904.a, the Commission may condition the approval of an Oil and Gas Development Plan on an operator's participation in studies evaluating the cumulative air impacts of oil and gas development. Staff anticipates that operators may incur costs to participate in these cumulative impacts studies as authorized by the Rule. However, the exact scope of participation is not governed by this Rule and, as a result, Staff is unable to calculate the costs to industry.

(Qualitative) Staff also expects there will be qualitative benefits associated with Rule 904. Due to industry participation in the studies envisioned by this Rule, academia and the community at large will receive up-to-date information about the cumulative air impacts of oil and gas development. This will have both short- and long-term benefits.

- **Impacts on State Government**

(FTE Cost) Staff did not identify any FTE costs associated with this Rule. However, Staff recognizes that it is likely that some agency staff time will likely be incurred to develop and oversee the studies contemplated by Rule 904. Some of this staff time will be incurred by the Commission's Staff, and some by the Air Pollution Control Division and potentially other divisions within CDPHE. However, Staff does not have sufficient information available about the anticipated scope and duration of the studies to quantify the exact FTE costs at this time.

(FTE Benefit) Staff did not identify any FTE costs or benefits associated with Rule 904.

(Qualitative) However, Staff also anticipates that state government will see qualitative benefits associated with Rule 904. Due to industry participation in the studies envisioned by this Rule, CDPHE will receive up-to-date information about the cumulative air impacts of oil and gas development. In addition, these studies will help the State as it implements Colorado House Bill 19-1261, Climate Action Plan to Reduce Pollution. These benefits are both short- and long-term.

Rule 905 – Management of E&P Waste

Staff moved the general requirements for management of E&P waste from prior Rule 907 to Rule 905. Many of the revisions to the rule were non-substantive, including updates to certain definitions and incorporations by reference. Rule 905.a includes a new requirement for the submission of a comprehensive waste management plan. Although waste management plans were submitted in some circumstances under the Commission's prior 900 Series Rules, the new requirement for a waste management plan in every circumstance under proposed Rule 905 will ensure that Staff has the opportunity to work with the operator up front at the Form 2A planning stage to ensure the operator is prepared to manage E&P waste in a manner that avoids, minimizes, and mitigates potential adverse environmental impacts. Rule 905.a also includes updated language to match SB 19-181's revisions to the definition of "minimize adverse impacts," and updates the incorporation by reference of WQCC Regulation 41 to match the updated incorporation by reference in Rule 901.b. Rules 905.c–g detail the requirements for E&P waste transportation and managing certain categories of E&P wastes like produced water, drilling fluids, oily waste, drill cuttings, and other E&P waste.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 905 will result in costs to industry. First, Rule 905.a.(4) requires operators at new oil and gas locations generating E&P waste to submit a comprehensive Waste Management Plan. However, this requirement does not extend to existing oil and gas locations unless an operator proposes a significant modification that requires submission of a new or revised Form 2A. Staff analyzed the cost to industry associated with this rule as part of its analysis of Rule 304 – Form 2A, Oil and Gas Location Assessment Application, contained in the 200–600 Series Rules Cost-Benefit Analysis, and accordingly did not duplicate that analysis in this 900 Series Cost-Benefit Analysis.

Second, Rule 905.c.(5) requires an operator to submit any proposed water sharing plan to the Director for approval or denial no less than 60 days in advance of implementation. Staff projects that only five water shares per year will be impacted by this requirement and that each water share submittal will cost approximately $2,200. Staff estimates that industry will incur a total annual cost of $11,000 utilizing technical staff or consultants to prepare each submittal.

Third, Rule 905.g governs treatment and disposal of drill cuttings. Under Rule 905.g.(2), operators must sample and analyze drill cuttings to demonstrate compliance with Table 915-1 before selecting an appropriate treatment or disposal method. Staff estimates that operators will collect and analyze 100 samples across 10 drill cuttings management locations per year. Staff approximates this will occur at a rate of one sample every 100 cubic yards, and that sampling costs will be broken out as follows: 10 samples to demonstrate compliance with Table 915-1, costing $543 per sample; and 90 samples to test for benzene, toluene, ethylbenzene and xylene (BTEX), total petroleum hydrocarbons (TPH), and other inorganic compounds, costing $110 per sample. This will result in a total annual cost to industry of $15,330. **Table 6** (below) provides additional detail for this calculation.

Table 6 – Impact Calculation Detail for Rule 905.g

impact scenario / item	unit	low value	high value
INDUSTRY COST			
Drill Cuttings Management Locations Affected by Rule	locations per year	10	10
Total Samples Taken Across All Locations	samples per year	100	100
Samples Analyzed Using Table 915-1 Requirements	samples per year	10	10
Cost per Table 915-1 Sample	2020$ / sample	$543	$543
Samples Analyzed for BTEX, TPH, and Inorganics Only	samples per year	90	90
Cost per BTEX, TPH, and Inorganics Sample	2020$ / sample	$110	$110
Subtotal, Total Cost	**2020$ per year**	**$15,330**	**$15,330**

(Qualitative) Staff expects that Rule 905 will also result in various qualitative benefits to industry and the community. First, Rule 905.a.(4)'s requirement for a waste management plan will promote improved up-front planning, helping operators reduce or avoid significant future costs associated with improperly handled waste. In addition, because operators will have the opportunity to consider different strategies for minimizing adverse environmental impacts prior to those impacts occurring, they will be less likely to cause pollution or adverse impacts to the environment, which will in turn earn greater public trust.

Second, Rule 905.d.(3) limits land application disposal of bentonitic drilling fluids on non-cropland. Pursuant to the updated rule, bentonitic fluids will no longer be dumped on non-cropland where there is no beneficial soil amendment needed. This will result in environmental benefits since it will encourage operators to continue best practices related to sampling for potential contaminants of concern and prevent surface damage to large acreages of non-cropland that would result in surface reclamation. Because Land Application is one of three options for treatment and disposal under Rule 905.d, it is difficult to determine how many locations may be impacted. Accordingly, Staff did not quantify the qualitative benefits of this Rule. Nevertheless, the qualitative benefits to the environment and to agricultural production are expected to be significant.

Third, Rule 905.e, which describes the options available for treating and disposing of oily waste, will result in benefits to industry and the community. The rule ensures that both onsite and off-site oily waste disposal practices are conducted in ways that are safe and protective of the environment. More specifically, the requirements found in subsection (2) will ensure that operators have authorization from surface owners and have documented such approval with the Commission prior to commencing any Land Treatment. By doing this, there will be less of a chance that an operator contaminates a private surface not intended for oil and gas activities. These requirements will also ensure that operators perform remediation in a timely manner and refrain from off-site Land Treatment once the last well has been plugged. Staff estimates that these qualitative benefits will apply to five to 10 locations per year.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur costs associated with Rule 905. Environmental Staff estimates that it will spend about five hours reviewing each Waste Management Plan submitted in compliance with Rule 905.a.(4). Staff analyzed the FTE cost associated with this rule as part of its analysis of Rule 304 – Form 2A, Oil and Gas Location Assessment Application, contained in the 200–600 Series Rules Cost-Benefit Analysis, and accordingly did not duplicate that analysis in this 900 Series Cost-Benefit Analysis.

In addition, Environmental Staff assumes that it will take about 40 hours to review each produced water sharing plan submitted pursuant to Rule 905.c.(5). Assuming five water sharing plans will be reviewed each year, the annual impact on Staff will be 0.096 FTE.

Environmental Staff also anticipates that Rule 905.g will require additional review of the Waste Management Plans submitted and additional site inspections for each drill cuttings management location. Staff assumes it will take 20 hours to review each plan and an hour and a half for each site inspection of a drill cuttings management location. Staff estimates this requirement will apply at 10 locations per year, resulting in an annual cost of 0.103 FTE.

(FTE Benefit) Staff also expects that it will incur benefits to offset some of the costs associated with Rule 905. As a result of Rule 905.a.(4), Environmental Staff will likely process fewer Form 27s due to increased operator compliance and expects to benefit 0.024 FTE as a result. Staff did not analyze the benefit to the agency associated with this Rule as part of its analysis of Rule 304 – Form 2A, Oil and Gas Location Assessment Application, which was contained in the 200–600 Series Rules Cost-Benefit Analysis. Because Environmental Staff will be involved in the processing of Form 27s under this Rule, an FTE benefit has been noted here.

Next, Environmental and Field Inspection Reclamation Staff assumes that under Rule 905.d.(3), less oversight will be necessary to monitor locations where bentonitic fluids would have been disposed under the previous Land Treatment requirements. Staff estimates this rule will apply to five locations annually, resulting in a benefit of 0.096 FTE.

Finally, Environmental and Field Inspection Reclamation Staff expects that Rule 905.e will reduce the amount of oversight necessary to monitor locations where oily waste would have been disposed under the previous Land Treatment requirements. Staff estimates that this rule will apply to five and 10 locations annually, resulting in a benefit of 0.120 to 0.192 FTE.

Rule 907 – Centralized E&P Waste Management Facilities

Staff relocated prior Rule 908 governing centralized E&P Waste Management facilities to Rule 907. Many of the changes to Rule 907 do not result in substantial changes to the process previously contained in prior Rule 908. Consistent with Senate Bill 19-181's changes to the Commission's statutory authority and mission, the updates to this rule ensure that operators proposing Centralized E&P Waste Management Facilities consider the protection and minimization of adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

- **Impacts on Industry and the Community**

Staff assumes two costs to industry associated with Rule 907. First, Rule 907.b.(6) requires operators to complete a characteristic waste profile for each waste type to be treated. Waste profiles must include an analysis of representative waste samples by an accredited laboratory, which clarifies an area of ambiguity under prior Rule 908.b.(6). Staff

($ Cost) anticipates that this rule will apply mainly to operators on the Western Slope, requiring 500 samples per year at a cost of $1,600 per sample. Accordingly, Staff estimates that the annual impact on industry will be $800,000.

Second, Rule 907.b.(7) now includes a requirement that facility design, engineering, and as-constructed plans be reviewed and stamped by a certified Colorado Professional Engineer ("P.E."). Because these facilities are generally built for long term operation to handle E&P Waste, Staff included this requirement to decrease the risk to public safety and the environment that occurs if these facilities are not designed and operated properly. For portions of the plans that can be reviewed and approved by a P.E., it provides some assurance to Staff that the design is adequate. Staff estimates that each review by a P.E. will take 20 hours and apply at four proposed locations, or Form 2As, per year for a total cost to industry of $12,000 annually.

(Qualitative) Staff expects that Rule 907 will result in qualitative benefits to industry, the community, and local governments. Because Rule 907.b.(7) now requires a P.E. to review and stamp all facility design, engineering, and as constructed plans, public trust in industry will improve. It is also less likely that unintentional oversights in facility design may result in future environmental harm. This Rule will result in short- and long-term benefits.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur some costs associated with Rule 907. Environmental Staff estimates that as a result of Rule 907.b.(6), it will receive 500 Form 44s from operators on the Western Slope, which will require 0.5 hours per form to review and process. This will result in an annual cost of 0.120 FTE.

In addition, under Rule 907.b.(7), Environmental and Oil and Gas Location Assessment Specialist Staff assumes that it will process four more Form 28s per location annually and spend 40 hours on each form. This will result in an annual cost of 0.077 FTE.

(FTE Benefit) Staff also expects to incur a benefit to offset some of the costs associated with Rule 907. Environmental Staff assumes that as a result of Rule 907.b.(7), mistakes in permit documentation submittals will decrease, which will reduce the time spent in review. Staff estimates that eight hours will be saved on four fewer Form 2As annually, which will result in a benefit of 0.015 FTE.

Rule 908 – Pit Permitting/Reporting Requirements

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 Report/Permit. Staff simplified the language of prior Rules 903.a and 335 to list four categories of new pits that require approval by the Director. This Rule also imposes reporting requirements on industry concerning all new pit construction, enlargement or modification of an existing pit facility, and the construction of emergency pits or cuttings trenches. The Rule also provides the Director with the discretion to condition the approval of proposed pits on compliance with additional terms, provisions, or requirements necessary to protect public health, safety, welfare, the environment, and wildlife resources.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes two costs to industry associated with Rule 908. First, the provisions of Rule 908.a require Director approval for any proposed new pit construction. Under Rule 908.a.(3), operators will be required to produce pit drawings for each Form 2A filing and submit a new Form 15 for all new or substantially modified drilling pits. This change to reporting requirements will improve the Commission's approach to fluids management. Generally, oil and gas operations have shifted away from using pits, and the number of pit permitting applications has declined dramatically in recent years. For example, new pit permitting applications declined from 455 in 2005 to three in 2019. Therefore, Staff estimates this requirement will impact approximately 10 proposed oil and gas locations per year at a cost of $2,000 per Form 2A. The annual impact to industry will be $20,000.

Second, Rule 908.c revises the categories of pits that operators may construct without prior Commission approval to include three types of emergency pits and cuttings trenches.

Operators must still submit a Form 15 for approval within 30 days of constructing each pit or trench. However, Rule 908.c.(2) will also require an operator to produce location drawings to complement each Form 2A. As mentioned in the previous paragraph, this requirement will improve the Commission's approach to fluids management. Staff assumes that this requirement will impact 4 locations per year at a cost of $2,000 per Form 2A. This will result in an annual cost to industry of $8,000.

(Qualitative) Staff also expects that Rule 908 will generate qualitative benefits to industry and the community. Rule 908.a.(3) and Rule 908.c.(2) both contemplate that operators submit robust permitting packages to the Commission. As a result, surface owners, operators, and local government will be able to verify that there are no public health, safety, welfare, environment, or wildlife concerns with their proposed or substantially modified pits. This will instill industry with a level of confidence that pits are properly constructed to avoid adverse impacts and in turn improve public trust in industry operations. Relatedly, industry will avoid expensive remediation of improperly disposed drill cuttings.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur costs associated with Rule 908. Due to Rule 908.a.(3)'s requirement that pit drawings accompany any Form 2A proposing a drilling pit, Staff's Oil and Gas Location Assessment team will likely spend an additional two hours reviewing each form. Staff anticipates that this rule will apply at 10 locations, resulting in a total annual cost of 0.010 FTE.

Staff anticipates that it will incur additional costs based on Rule 908.c.(2)'s requirement to submit pit drawings for emergency pits and cuttings trenches that do not require prior approval. Staff estimates that the Oil and Gas Location Assessment team will spend an additional two hours per Form 15 and that this requirement will apply to 4 locations annually. This will result in an annual cost of 0.004 FTE.

(FTE Benefit) Staff expects it will also incur benefits to offset some of the costs associated with Rule 908. The requirements in Rules 908.a.(3) and c.(2) that operators provide detailed drawings of proposed pits and emergency pits and cuttings trenches that do not require prior Commission approval will result in a savings to the Commission. Environmental Staff will spend less time researching this information. Importantly, Environmental Staff will also avoid some of the time typically spent on issues related to spills and reclamation. Staff estimates there will be FTE benefits associated with each Rule. Staff anticipates that one fewer spill and remediation issue will arise per year as a result of Rule 908.a.(3)'s requirement to submit additional drawings for new pits. Staff will likely save an hour and a half per issue, resulting in an annual decrease in workload of 0.001 FTE. With respect to Rule 908.c.(2), Staff assumes that while there will be fewer spill and reclamation issues that arise each year as a result of Rule 908.c.(2), the FTE benefit is too small to quantify.

Rule 909 – Pits – Construction and Operation

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. Rule 909 is generally prospective and applies only to operations that are new or significantly modified after November 2, 2020 unless otherwise specified. However, in certain circumstances, components of Rule 909 that involve ongoing activities or operations that occur at existing pits after the effective date of the 800/900/1200 Mission Change Rulemaking will apply to existing pits.

Impacts on Industry and the Community

($ Cost) Staff assumes a few costs to industry associated with Rule 909. First, Rule 909.a governs permitting and reporting for operational pits. Pursuant to this rule, operators are required to ensure the Commission receives up to date information on all operational pits. Staff determined this rule was necessary because frequent challenges with remediation and reclamation projects have arisen as a result of operators' failure to document the location and status of operational pits. This Rule will apply to the 5,704 pits currently in existence statewide that require updated operator information. Staff estimates operators will incur a cost of $1,500 per pit to compile and update pit operator information. This results in a one-time cost to industry of $8,556,000.

Second, Rule 909.f requires operators to fence and net or install CPW-approved exclusion devices on all new and existing pits in accordance with Rule 1202.a.(4). In an effort to avoid double counting these impacts, the costs to industry will be addressed below in the analysis of the 1200 Series Rules.

Lastly, Rule 909.j governs produced water quality analyses for produced water that is placed into pits. The Commission's prior Rules called for limited sampling and analysis of produced water on a case-by-case basis, but those Rules did not provide operators with comprehensive sampling and analysis procedures for produced water. The purpose of new Rule 909.j is two-fold: the Rule ensures that operators sample produced water contained in pits and that the Commission receives accurate data about produced water in all pits in the State. In an effort to provide operators with sufficient time to implement the new sampling protocol, the Rule allows operators one year from the effective date of the Mission Change Rules to conduct their first sample, and a year and a half from the effective date to submit the sampling data to the Commission. Staff anticipates that Rule 909.j will result in both one-time and annual costs to industry. Operators of existing wells that continue to send produced water to active pits will incur a one-time cost per well of $1,600 to prepare and file a Form 43 with the help of technical staff or a consultant. Staff estimates there are currently 3,357 active pits statewide that fall under these requirements, which results in a one-time cost to industry of $5,371,200. Operators of new wells that send produced water to pits will also incur a $1,600 cost per well to prepare and file a Form 43 with the help of technical staff or a consultant. Staff estimates that this requirement will apply to 110 pits annually, with a total annual cost to industry of $330,000.

(Qualitative) Staff assumes there will be qualitative benefits associated with Rule 909. Rule 909.a.'s requirements will benefit landowners and local governments in the short- and long-term. Since this Rule will cause pit facilities records to be properly updated, there will likely be a locatable responsible party for the facility in terms of closure and any remediation costs. In the past many of these facilities became stranded with no current operator of record potentially causing closure and cleanup to be performed by the Orphan Well Program.

Rule 909.j's produced water quality analysis requirements will benefit industry. By profiling produced water, operators will be able to depend upon laboratory analyses to evaluate current and future waste handling, support produced water spills and releases, clean up projects, and provide reliable water data when addressing landowner and local government concerns. The requirement to profile produced water may also help operators satisfy Rule 903.d.(6) if the analysis includes information on BTEX to estimate VOCs. Additionally, operators will be able to test for technologically enhanced naturally occurring radioactive materials (TENORM) early on so that they can show there will be no impacts from these materials at the end of the pit's lifespan.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur costs associated with Rule 909. Staff expects to incur both one-time and annual costs as a result of Rule 909.a. Staff estimates that it will spend one hour per pit report to review submissions that will bring current pits into compliance. This will apply to 5,704 pits statewide that require updated operator information and result in a one-time cost of 2.742 FTE. Following the initial updates, Staff estimates it will then spend one hour per pit report to review submissions covering new pits. Since new pit construction has generally decreased over recent years, this requirement will likely cover 10 pits per year and increase Staff's annual workload by 0.005 FTE.

As discussed in the "Impacts on Industry and the Community" section of this Rule, costs to Staff associated with Rule 909.f will be addressed below in the analysis of the 1200 Series Rules.

Staff also expects to incur both one-time and annual costs associated with Rule 909.j. Staff estimates that it will spend 0.5 hours per Form 43 to review submissions documenting operators' produced water analyses. This will apply at the 3,357 existing pits statewide that require a produced water quality analysis and result in a one-time cost of 0.807 FTE. Following the initial updates, Staff estimates it will then spend 0.5 hours per Form 43 to review submissions documenting operators' produced water analyses from new wells sending produced water to pits. This requirement will likely apply to 110 Form 43's per year and increase Staff's annual workload by 0.026 FTE.

($ Benefit) Staff assumes there will be benefits associated with Rule 909. Due largely to Rule 909.a's requirements to update pit records with the Commission, the State of Colorado's Orphaned Well Program ("OWP") will not have to expend funds to remediate and properly close a portion of orphaned locations with pits. Because Staff will have up-to-date operator information, Staff will be able to better track and ensure proper remediation and closure of pits that otherwise may have become stranded under the prior Rules. Staff estimates that the State will avoid $50,000 in OWP costs for 10% of the 5,704 pits that currently require updated operator information, resulting in a one-time benefit of $28,500,000.

(FTE Benefit) Staff also expects that Rule 909.a will result in a reduction in workload because as the Commission's records are updated, Staff will not need to expend additional significant effort researching old records to identify potentially responsible parties or identifying former pits that may not have been properly closed. Staff approximates that they will save one hour per candidate pit for closure. This will apply to 500 pits, and result in a one-time benefit of 0.240 FTE.

Finally, Staff expects that the produced water analysis requirements of Rule 909.j will equip them with the information necessary to more efficiently evaluate spills and releases. Staff estimates that they will spend four fewer hours per incident fielding questions and complaints that can be answered with a review of the operator's produced water analysis. This will likely apply to 25 incidents per year and result in a benefit to Staff of 0.048 FTE.

Rule 910 – Pit Lining Requirements and Specifications

Staff moved prior Rule 904, governing pit lining requirements and specifications, to Rule 910. Several revisions were made to Rule 910 to reflect the Commission's updated mission and statutory authority following the adoption of SB 19-181. The Rule requires the lining of most new pits constructed after the effective date of the Mission Change Rulemaking and all skim pits, regardless of date of construction. In addition, the rule provides operators with comprehensive new pit construction requirements and consolidates all pit standards into a single set of regulations applicable statewide.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes three costs to industry associated with Rule 910. First, Rule 910.a requires lining of all new pits constructed after the effective date of the Mission Change Rulemaking. Staff determined that unlined pits present an unjustifiable risk of environmental harm to soil, surface water, and groundwater and such risk is inconsistent with SB 19-181's changes to the Commission's mission and statutory authority. This Rule does not apply to cuttings trenches and pits constructed as an initial emergency response measure because they do not pose the same type and duration of environmental harms as unlined pits. Staff anticipates that this requirement will apply to 10 pits per year, as oil and gas operations have generally shifted away from using pits in recent years. Staff estimates that it will cost operators between $20,000 and $50,000 per newly constructed pit to comply with Rule 910.a. This results in an annual cost to industry between $200,000 and $500,000.

Next, Staff revised the standards for skim pits in Rule 910.b. Skim pits are typically used to provide retention time for the settling of solids and separation of residual oil for the purpose of recovering the oil or fluid. Therefore, skim pits inherently contain oil and other hydrocarbon substances. Under Rule 910.b, existing skim pits must be lined regardless of the date of construction and no new skim pits will be allowed. Retrofitting existing skim pits with a liner is necessary and reasonable to protect the environment from contamination by hydrocarbon substances that are likely to leak into soil, surface water, or groundwater from beneath an unlined skim pit. For all unlined skim pits in existence on the effective date of the Mission Change Rulemaking, operators must submit a Form 27 outlining the operator's plan to either properly line or close the existing pit. Staff generally assumes that existing skim pits have been properly lined as required by prior Rules. However, Staff anticipates there will be costs to operators associated with the process to close a skim pit. Staff estimates that 100 pits will be closed under this Rule, with a cost to operators between $30,000 and $250,000 per pit. This will result in a total one-time cost to industry between $3,000,000 and $25,000,000. Staff determined that skim pits pose inherent and substantial risks to air, water, and soil that are not consistent with SB 19-181's changes to the Commission's mission and statutory authority.

Finally, Rule 910.f authorizes the Director to require the use of additional liners, a leak detection system, or other equivalent protective measures at pits on a case-by-case basis.

Staff expanded this requirement to apply statewide to align with SB 19-181's changes to the Commission's mission and statutory authority. Under this Rule, operators developing sites with new pits may be required to install certain protective measures. Staff estimates this requirement will apply to between one and 10 pits per year and result in a cost of between $1,000 to $250,000 per pit in protective measures. This results in an annual cost to industry between $1,000 and $2,500,000.

($ Benefit) Staff expects that there will be quantifiable benefits associated with Rule 910. First, as a result of the lining requirements for newly constructed pits found in Rule 910.a, Staff anticipates that operators will avoid the expense of costly remediation projects associated with unlined pits. Staff estimates this will apply to 10 new pits per year and that operators will save between $10,000 and $50,000 per pit. This results in an annual benefit to industry between $100,000 and $500,000.

Second, Staff expects that under Rule 910.f, operators will avoid costly remediation projects in certain cases due to the installation and success of the Commission's additional discretionary pit protective measures. Staff estimates this will apply to between one and 10 pits per year and that operators will avoid paying between $1,000 and $300,000 per pit in future remediation costs. This results in a benefit to industry between $1,000 and $3,000,000 annually.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur three costs associated with Rule 910. As a result of Rule 910.a's requirement that all newly constructed pits be lined, Environmental Staff anticipates it will spend two hours reviewing each Form 15 submitted and an hour and a half inspecting particular pit locations. This will apply to 10 pits per year, as new pit construction has trended downward in recent years. Staff estimates that Rule 910.a will result in an annual workload increase of 0.017 FTE.

Second, Environmental Staff assumes it will spend two hours reviewing each Form 27 submitted to comply with Rule 910.b's skim pit requirements and an hour and a half inspecting affected skim pit locations. This will apply to 100 pits and Staff estimates a one-time increase in workload of 0.168 FTE.

Third and finally, Staff expects to spend 20 hours reviewing additional Form 2A or Form 15 documentation associated with any pit requiring additional leak protection measures. Staff anticipates this will apply to between one and 10 pits per year, resulting in an annual increase in workload between 0.010 and 0.096 FTE.

(FTE Benefit) Staff also assumes it will incur benefits to offset some of the costs associated with Rule 910. Due to the new pit lining requirements in Rule 910.a, Environmental Staff anticipates it will have fewer remediation projects to process and close as operators line their new pits. This will apply to 10 pits per year and Staff will realize four hours of avoided time verifying proper closure at each pit falling under these requirements. Accordingly, this results in an annual benefit to Staff of 0.019 FTE.

Second, Environmental Staff expects that as a result of Rule 910.b, it will process between up to 50 fewer Form 27s as skim pits are closed. As a result, Staff estimates this will save 30 hours per each avoided remediation project. Staff will likely realize a maximum one-time staffing level benefit of 0.721 FTE.

Finally, Staff expects to avoid time consuming supervision of remediation on short- to long-term releases that would occur in the absence of Rule 912.f. Staff anticipates it will save 30 hours per each avoided supervision effort on remediations and between one and 10 pits per year. This results in an annual reduction in Staff workload between 0.014 and 0.144 FTE.

Rule 911 – Closure of Oil and Gas Facilities

Staff moved prior Rule 905, which governed closure of pits, to Rule 911 and expanded the Rule to provide standards for the closure of all oil and gas facilities. The Commission determined that adopting a single regulation to specify 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. For example, Rule 911.a was updated to require operators to complete a Form 27, Site Investigation and Remediation Workplan, and submit it to obtain the Director's approval, for all oil and gas facilities. Overall, with some of the retroactive requirements as well as better integrity management for oil and gas equipment, Rule 911 reflects an increased focus on preventing adverse environmental impacts that can arise at closure of an oil and gas facility. The Rule is intended to prevent the environmental harms that would otherwise make compliance costly.

- **Impacts on Industry and the Community**

($ Cost) Staff anticipates there will be costs to industry associated with Rule 911. First, Rule 911.a.(1)–(3) governs the requirements necessary for an operator to close any oil and gas facility. Under this rule, drilling pits now require a Form 27 in order to close. Staff determined it was important to document these workplans at all oil and gas facility closures in order to maintain accurate data and not waste resources. Of the Form 27s that will be submitted regarding pit closure, Staff expects that the data will reflect that 75% of the pits are clean, 20% will require additional soil removal, and 5% will have groundwater impacts. Staff assumes that this requirement will apply to 10 pits per year and that it will cost operators $5,000 to prepare each Form 27. This results in a total annual impact on industry of $50,000.

Next, Rule 911.a.(4) specifies a timeline for submitting a Form 27 for closure of all other oil and gas facilities not expressly mentioned in subsections (1)–(3). 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. 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. Staff assumes that operators will need to remediate an estimated one half of locations associated with wells that are plugged and abandoned by industry annually, and estimates this will occur at 950 locations per year. Staff anticipates it will cost industry $25,000 per location to perform the site assessment and submit the Form 27, which results in an annual cost to industry of $23,750,000.

(Qualitative) Staff also expects there will be qualitative benefits associated with Rule 911. The public will place more trust in industry when operators file the verifiable closure documentation required by Rule 911.a.(1)–(3). By adhering to a timeline for a site closure plan laid out in a Form 27 pursuant to Rule 911.a.(4), the community will benefit sooner from a higher level of environmental quality and public safety as locations with contamination are closed and remediated to meet soil and water quality standards. This Rule will improve environmental outcomes in several ways. Because there will be less contamination in the soil, crop and vegetation growth will be able to thrive. Also, preventing contaminants from entering the groundwater protects public health by avoiding contamination of water wells. Both of these outcomes in turn benefit entire ecosystems and wildlife. In addition, both industry and the community will be provided with a level of certainty that any residual contamination at these locations will be limited in scope. This will have both short- and long-term benefits.

- **Impacts on State Government**

(FTE Cost)

Staff assumes it will incur costs associated with Rule 911.a.(1)–(3). Staff estimates it will need to process 10 Form 27 remediation project submissions for pits per year and that it will spend approximately four hours per form. This is likely to result in an annual cost of Staff of 0.019 FTE.

Staff also expects to incur costs associated with Rule 911.a.(4) to process Form 27 remediation project submissions and perform inspections during operator closures of locations associated with plugging and abandoning wells. Staff estimates this will apply at 950 pits per year and that it will spend approximately two hours reviewing each form and an hour and a half inspecting each location. This results in an annual cost to Staff of 1.599 FTE.

($ Benefit)

Staff anticipates receiving a monetary benefit as a result of Rule 911.a.(4). Due in large part to the certainty provided by the timeline contained in an operator's Form 27 remediation project form, the State will, in the future, avoid paying for remediation of locations that are not properly closed under current Rules and become OWP projects. This will likely apply at 25 to 100 locations per year, reducing the State's OWP liability by $50,000 per location. The impact on the State will be between $1,250,000 to $5,000,000 annual benefit.

Rule 912 – Spills and Releases

Staff moved prior Rule 906, governing spills and releases, to Rule 912. This Rule details requirements for operators when discovering, investigating, and reporting spills or releases of E&P Waste, gas, or produced fluids. Rule 912 now specifies the types of spills or releases that must be reported and contains procedures for closure or follow up remediation from a spill or release. Staff also made changes to the Rule requiring more reporting and lower thresholds for spills that have to be reported so that it would conform with SB 19-181's changes to the Commission's mission and statutory authority. Rule 912 reflects an increased focus on preventing the adverse environmental impacts that can arise as a result of spills and releases of E&P Waste, gas, or produced fluids.

- **Impacts on Industry and the Community**

($ Cost)

Staff assumes there will be costs to industry associated with Rule 912. First, Rule 912.a contains general requirements for operators when managing any spills or releases of E&P Waste, gas, or produced fluids. Staff made changes to this Rule to reflect the change in the Commission's mission and many of these changes did not result in additional costs to industry. Under this Rule, operators must immediately investigate, clean up, and document such spills and releases. Rule 912.a.(5) now specifies that operators must provide clean up documentation for spills that do not meet the reporting requirements of Rule 912.b. Staff determined that it is appropriate to provide for documentation of these releases so that the Commission may comprehensively assess any risks to public health, safety, welfare, the environment and wildlife resources. Staff anticipates that operators will incur $500 of technical staff or consultant costs for each Form 15 that is required under this Rule. Staff estimates this requirement will apply to 100 spills per year, and that the total impact to industry will be $50,000 annually.

Next, Staff revised Rule 912.b.(1) and added criteria for reporting spills and releases. Under Rule 912.b.(1), operators will be required to report additional spills under the new spill thresholds. The Commission determined these updates were necessary to ensure that operators submit timely notifications of all spills and releases so that Staff can proceed with oversight, investigation, and remediation responses as appropriate. Staff anticipates that operators will incur between $500 and $1,250 of technical staff or consultant costs for each Form 19, Spill/Release Report, required under this Rule. Staff assumes this requirement will apply to 185 spills or releases per year, resulting in a cost to industry between $92,500 and $231,250 annually.

In Rule 912.b.(4), the Commission clarified and provided additional criteria for supplemental Form 19 Reports filed within 10 days of a spill. Pursuant to Rule 912.b.(4), operators must provide photographic documentation of the source of a spill or release, the impacted area, and any initial clean up activity. Staff determined this requirement is necessary because written descriptions may not provide Staff with enough information to determine an appropriate response. Staff estimates that this requirement will apply to about 735 supplemental Form 19s per year, and that operators will incur a cost of $50 per supplemental Form 19. This will result in an annual cost of $36,750.

Rule 912.b.(6) contains new procedures for closure or follow up remediation from a spill or release. Under this Rule, operators must submit, within 90 days of a spill or release, either a Form 19 to close the spill because it has been fully cleaned up in compliance with Table 915-1, or a Form 27 because additional investigation, cleanup, or remediation is still necessary. Staff determined the 90-day time frame was a reasonable time period to allow operators the chance to differentiate between relatively minor spills and spills that would require significant remediation efforts. Staff anticipates that for those spills requiring submission of an additional Form 27 at the Director's discretion, operators will incur $500 for technical staff or consultant costs associated with each spill. Staff estimates this will apply to 75 large spills per year, resulting in an annual cost to industry of $37,500.

The Commission adopted new Rule 912.b.(10), which requires operators to report spills and releases that occur within high priority habitat or within 300 feet of surface Waters of the State to Colorado Parks and Wildlife. This notification will ensure that CPW can assess the spill as it pertains to impacts on wildlife resources and make recommendations to the Commission about additional mitigation or enforcement. Staff estimates that this requirement will apply to 50 spills per year and cost $50 in technical staff time per notification following a spill. This will result in a $2,500 annual cost to industry.

Rule 912.e provides procedures for operators to close a suspected spill or release that ultimately proved not to exceed any applicable reporting thresholds, which is consistent with changes in Rule 912.b.(1) requiring operators to report suspected spills or releases. 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. Costs to industry associated with the revised reporting requirements are discussed above in Rule 912.a.(5).

Finally, Rule 912.f requires new operators of a facility with an active Form 9 to file a supplemental Form 19 to designate which operator is responsible for closing open spills and releases related to a facility whose ownership transfers from one operator to another. The Form 9 is a new form adopted as part of the 200–600 Mission Change Rulemaking and requires operators to designate responsibility for each facility that has been transferred. Under the prior Rules, Staff did not have a system for tracking changes of operator. Staff anticipates that this requirement will apply to 181 transfers per year and that it will take operators' technical staff or consultant an hour and a half to prepare and submit each supplemental Form 19. This will result in an annual cost to industry of $40,725.

(Qualitative)

Staff next assumes there will be qualitative benefits associated with Rule 912. Because of Rule 912.b.(1)'s reporting requirements, the community will benefit from overall improvements to public health, safety, welfare, and environmental quality as operators take action to address additional spills and releases. Staff expects these benefits to be both short-term and long-term.

Rule 912.b.(4) will result in another qualitative benefit for the community. Because operators will have to submit photographic documentation of the spill or release in any supplemental Form 19, the public will benefit from greater transparency—especially the extent of data and information—provided by operators. This will also increase the public's trust in industry, which will have short- and long-term benefits.

The community will also benefit from the requirements of Rule 912.b.(6) because of improvements to public health, safety, welfare, and environmental quality as operators are required to commit to clean up timelines for larger spills. Staff expects these benefits to be both short-term and long-term.

Rule 912.b.(10) will also result in a benefit to wildlife because operators will notify CPW about certain spills that may impact wildlife in sensitive areas. Staff expects that 50 spills per year will fall under this Rule's notification requirement and that the benefits will be both short- and long-term.

- **Impacts on State Government**

(FTE Cost)

Environmental Staff assumes it will incur costs associated with Rule 912. Due to Rule 912.a.(5)'s requirement to provide clean up documentation for spills not meeting the requirements of Rule 912.b, Staff anticipates it will spend a half hour reviewing each Form

15 submitted in compliance. This will likely apply to 100 spills or releases per year, resulting in an annual cost to the Commission of 0.024 FTE.

Rule 912.b.(1)'s reporting requirement for additional spills and releases will require Environmental Staff to process additional Form 19s and perform more inspections on the associated spills or releases. Staff estimates that this will apply to 185 spills and 45 inspections per year, requiring an additional half hour per Form 19 and an additional hour and a half per inspection. This results in an annual cost of 0.077 FTE.

Environmental Staff anticipates that Rule 912.b.(4)'s photographic documentation requirement for each supplemental Form 19 will require additional processing time. Staff estimates that 0.15 hours will be spent on each supplemental Form 19, and that 735 supplemental Form 19s will be received per year. This results in an annual cost of 0.053 FTE.

Rule 912.b.(6)'s discretionary reporting requirement for additional information on large spills or releases will require Environmental Staff to process additional Form 27s. Staff estimates that this will apply to 75 projects dealing with large spills per year, requiring an additional half hour per Form 27. This results in an annual cost of 0.018 FTE.

Finally, Environmental Staff expects that as a result of Rule 912.f's requirement to submit supplemental Form 19s for open spill reports upon transfer of operatorship, it will spend an additional half hour reviewing each of the 181 supplemental Form 19s associated with transfer of ownership submitted per year. This results in an annual cost of 0.044 FTE.

(FTE Benefit)

Staff assumes it will incur benefits to offset some of the costs associated with Rule 912. First, Staff anticipates that it will process fewer complaints related to unreported spills as a result of the requirements in Rule 912.b.(1). Staff estimates that it will receive 10 fewer complaints per year, which would have resulted in eight hours of time per complaint. This results in an annual benefit of 0.038 FTE.

Next, Environmental Staff expects that due to the requirement in Rule 912.b.(4) to provide photographic documentation for each supplemental Form 19, Staff may rely on such documentation in selected cases in lieu of performing a site inspection. Staff estimates this will apply to 74 spills per year, avoiding an hour and a half per field inspection. This will result in an annual benefit of 0.053 FTE.

Environmental Staff also expects that for certain larger projects, it will spend less time managing the remediation timeline as a result of the requirements in Rule 912.b.(6). Staff estimates that this will apply to 50 projects per year, which is a subset of the larger spill projects. Staff anticipates a half hour will be saved per Form 27, resulting in an annual benefit of 0.012 FTE.

Rule 910.b.(10)'s notification requirement will also save Environmental Staff time coordinating with CPW on spill responses in high priority habitat or within 300 feet of surface Waters of the State. Staff estimates this requirement will apply to 50 spills per year and require a half hour less to review each Form 19 submitted in conjunction with a spill or release. This will result in a benefit to the Commission of 0.012 FTE annually.

Environmental Staff anticipates that as a result of Rule 912.e, less time will be spent negotiating with some operators about whether a spill report is required for certain categories of spills. This will apply to 10 spills per year and require 10 fewer Staff hours per spill. This will result in an annual benefit of 0.048 FTE.

Finally, Environmental Staff expects that as a result of the requirements in Rule 912.f, time and effort will be saved managing spills and remediation projects as responsibility for the remediation efforts in question are properly documented. This will apply to 181 supplemental Form 19s per year and require two fewer hours to review each form. This results in a benefit of 0.174 FTE annually.

Rule 913 – Site Investigation, Remediation, and Closure

Staff moved prior Rule 909, governing site investigation, remediation, and closure, to Rule 913. This Rule requires all site investigation, remediation projects, and decommissioning of oil and gas facilities to be conducted in accordance with the Commission's Rules. Generally, the Rule requires operators to generate site investigation and remediation workplans, conduct sampling and analyses, and conduct remediation activities when closing a site. The Rule generally requires the submission of a Form 27, Site Investigation and Remediation Workplan, when an operator closes a site. Rule 913 reflects Staff's increased focus on preventing adverse environmental impacts that can arise during site investigation, remediation, and closure. The Rule is intended to be easier to comply with while preventing the environmental harms that would otherwise make compliance more costly.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes there will be costs to industry associated with Rule 913. First, Rule 913.c governs the use of Form 27s prior to conducting certain operational and remediation activities. Under Rule 913.c.(9), operators are required to prepare and obtain the Director's approval of a Form 27 prior to decommissioning an oil and gas facility. Staff expects to receive a Form 27 from an operator prior to plugging and abandonment activities and prior to removing flowlines; Staff does not expect an operator to submit a Form 27 for a facility that is not being completely decommissioned. Staff anticipates that this new requirement will apply at 958 locations statewide per year and cost $2,000 per location. As a result, industry will incur a cost of $1,916,000 annually. Staff envisions that operators will submit a Form 27 to verify there are no residual impacts from production at the oil and gas location and before financial assurance is released to the operator.

Next, Rule 913.e sets forth a quarterly reporting schedule for operators following the initial approval of a Form 27. The Rule requires operators to submit supplemental Form 27s to document progress made on site investigation and remediation work. Staff 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. Rule 913.e.(2) requires 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 within three months of the effective date of the 800/900/1200 Mission Change Rulemaking. This new requirement will serve as an initial quarterly report and provide the Commission's Staff with a baseline to evaluate future quarterly progress reports against. Staff assumes that operators will incur a cost of $2,000 per location to provide baseline documentation of project process. Staff estimates there are

700 existing locations that will be subject to this Rule, resulting in a one-time cost to industry of $1,400,000.

Rule 913 also sets forth a provision in subsection e.(3) that generally requires operators to adopt a quarterly reporting schedule for all existing remediation projects approved prior to the effective date of the 800/900/1200 Mission Change Rulemaking unless a more frequent or specific reporting schedule was already approved by the director. Staff anticipates that this requirement will apply to 250 locations per year and that operators will incur $500 in technical staff or consultant effort to comply with the quarterly reporting requirements. This results in an annual cost to industry of $125,000.

Finally, Rule 913.g requires operators to report spills and releases discovered during facility closure operations on a Form 19. The costs to industry associated with this rule are detailed above in the analysis of Rule 912.f.

(Qualitative)

Staff assumes there will be qualitative benefits associated with Rule 913. As a result of Rule 913.e.(2), local governments and the general public will be provided with more transparent and timely information about the status of historical remediation projects. As a result, public trust in industry and confidence in regulatory outcomes will improve based on the status reporting required under the Rule. This will have both short- and long-term benefits.

As a result of Rule 913.e.(3), operators will save time and money by closing projects more quickly than if no reporting were required by the Commission. Increased oversight as a result of this Rule will ensure that operators have approved workplans and communicate closely with the Commission, likely preventing the need for Staff to request that operators do additional remediation work. Staff estimates that this will apply to 250 locations per year but does not have sufficient data available to quantify the monetary benefit.

- **Impacts on State Government**

(FTE Cost)

Staff assumes it will incur costs associated with Rule 913. Due to Rule 913.c.(9)'s requirement to submit a Form 27 when any oil and gas facility is decommissioned, Environmental Staff expects to review additional forms associated with these locations. Staff estimates this will apply to 958 locations per year and require four hours to review each submission. This will result in an annual workload increase of 1.842 FTE.

Environmental Staff also expects to review additional Form 27s as a result of Rule 913.e.(2)'s requirement for operators with open remediation projects to submit a detailed project summary and status. Staff anticipates it will spend one hour reviewing this information in each supplemental Form 27. Staff estimates there are 700 existing locations that will be subject to this requirement, resulting in a one-time workload increase of 0.337 FTE.

Finally, Environmental Staff projects that it will review additional Form 27s under a more frequent reporting schedule pursuant to Rule 913.e.(3). Staff estimates that this requirement will apply at 250 projects and require the submission of three additional forms per year. Staff assumes it will spend a half hour reviewing each additional Form 27, resulting in an annual increase to workload of 0.180 FTE.

($ Benefit) Staff assumes there will be a monetary benefit associated with Rule 909. Due to Rule 913.c.(9)'s requirement to submit a Form 27 each time an oil and gas facility is decommissioned, Staff will be better able to track outstanding remediation and facility closure projects. The State of Colorado's OWP will not have to expend funds to remediate a portion of the locations that may become orphaned in the future where an insolvent operator does not complete a remediation project. Staff estimates that the State will avoid $40,000 in OWP costs for each of the 48 estimated open projects that otherwise might become orphaned with remediation and facility closure projects still outstanding, resulting in a one-time benefit of $1,920,000.

(FTE Benefit) Staff also assumes it will incur FTE benefits to offset some of the costs associated with Rule 913. As a result of implementing the standards contained in Rule 913.b.(5), Environmental Staff anticipates that less time will be spent consulting on remediation projects as operators understand the remediation requirements and implement them. Staff anticipates that eight- to 12-hours per location will be saved each year, and that the Rule will apply to 10% of the estimated 250 new locations each year. This results in an annual benefit of 0.095 to 0.144 FTE. Staff assumes this time savings is ongoing even as operators learn from and adhere to the new standards.

Environmental Staff expects that due to the requirement in Rule 913.e.(2) to submit a supplemental Form 27 detailing each open remediation project and its status, Staff will spend less time contacting operators for updated information on such remediation projects. Staff estimates this will apply to 100 projects, avoiding an hour of time per remediation project. This will result in a one-time benefit of 0.048 FTE.

Next, Staff expects to receive and process fewer complaints on incomplete remediation projects as a result of the more frequent project status reporting schedule in Rule 913.e.(3). Staff estimates it will receive 10 fewer complaints per year and save eight hours per complaint. This will result in a benefit of 0.038 FTE.

Finally, Staff anticipates that the State will see a monetary benefit from Rule 913.e.(3). Due to more frequent reporting requirements, the State will likely avoid paying for remediation of locations with insolvent operators who failed to compete such projects. Staff anticipates this scenario will apply at one orphaned well project per year and that the State will avoid a cost between $42,000 to $175,000 annually.

<u>Rule 915 – Concentrations and Sampling for Soil and Groundwater</u>

Staff moved prior Rule 910 to Rule 915, and Table 910-1 to Table 915-1. Staff also updated Rule 915 to provide clearer standards for the remediation and reclamation of soil and groundwater at oil and gas locations. The Rule also updates prior Table 910-1, which relied on an outdated document—CDPHE's Hazardous Materials and Waste Management Division's 2007 Colorado Soil Evaluation Values. Table 915-1 now incorporates the U.S. EPA's Regional Screening Levels ("RSLs") for Chemical Contaminants at Superfund Sites for soil and groundwater concentrations, which is the standard now used by CDPHE. Staff also updated Rule 915 to provide a clearer directive on sampling and analysis methods.

- **Impacts on Industry and the Community**[3]

($ Cost) Staff assumes there will be costs to industry associated with Rule 915. First, Rule 915.a requires operators to adhere to the concentrations for soil cleanup in Table 915-1. The Rule establishes a presumption that EPA's RSL soil screening levels will apply, and that EPA's groundwater soil screening levels will apply only where evidence shows that a pathway to groundwater exists. The more protective standard will ensure lower soil concentrations at certain locations, potentially meaning that these remediated locations can be subject to a variety of land uses in the future. Operators subject to the groundwater soil screening cleanup levels will likely incur a cost of $4,750 per spill. Staff approximates that this requirement will apply to 36 spills per year, and result in an annual cost to industry of $171,000.

Next, Rule 915.b governs soil suitability for reclamation and requires operators to adhere to standards contained in Table 915-1. In certain circumstances when operators leave materials with elevated concentrations in situ, they must provide a detailed reclamation plan to the Commission. Although these expectations applied under the prior Rules, due to confusion over the regulatory standards, Staff determined that codifying these provisions was necessary to establish clear regulatory expectations for operators and improve regulatory certainty. Staff estimates that operators would need to submit a reclamation plan for 100 sites per year and that this would cost operators $1,200 per project. This results in an annual cost to operators of $120,000.

Rule 915.c requires operators to adhere to the concentrations for groundwater in Table 915-1. Staff derived the groundwater cleanup concentrations in Table 915-1 from the WQCC's Regulation 41 groundwater quality standards and classifications. This Rule provides clearer standards for groundwater cleanup concentrations and comports with SB 19-181's directive to minimize adverse impacts from oil and gas operations. Staff assumes that this requirement will apply at 550 projects, with 14 average wells per project requiring four samples per year. Staff estimates it will cost an operator $25 per water well sampled, resulting in an annual cost to industry of $770,000. **Table 7** (below) provides the detail for this calculation.

[3] The impacts associated with Table 915-1 are cross-listed with the analyses for Rules 915.a and b.

Table 7 – Rule 915.c Impact Calculation Detail

impact scenario / item	unit	low value	high value
INDUSTRY COST			
Operator Remediation Projects Subject to New Rule	projects per year	550	550
Average Wells Per Project	wells / project	14	14
Samples Analyzed Per Year	samples / well	4	4
Increased Cost to Complete Analyses Required in New Rule	2020$ per sample	$25	$25
Subtotal, Total Cost	**2020$ per year**	**$770,000**	**$770,000**

Rule 915.e sets forth the requirements governing sampling and analysis methods, incorporating EPA's SW-846 analytical methods by reference and providing operators with the possibility of using analytical methods published by other nationally recognized standards organizations with Director approval. 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. Staff anticipates operators will incur the following costs as a result:

- Under Rule 915.e.(3).B, operators are required to immediately collect groundwater samples from areas immediately downgradient or in the middle of excavated areas in close proximity to a 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 the appropriate samples to characterize the nature of contamination. Staff anticipates this requirement will apply at 20 locations per year and cost operators $10,000 to $50,000 per location. This results in a cost to industry between $200,000 to $1,000,000 annually.
- Rule 915.e.(3).C requires operators to analyze samples for groundwater contaminants of concern listed on Table 915-1. The Rule also provides operators with an option to request Director approval of a modified list of constituents of concern, based on site-specific E&P waste profiles and process knowledge. To pursue this option, operators must submit a Form 19 or Form 27. 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 in order to obtain approval of an alternate standard. Staff anticipates that if operators pursue this modified list, this requirement will apply to five locations per year and require an expenditure of $750 to demonstrate an absence of compounds of concern. This results in an annual cost to industry of $3,750.
- Rule 915.e.(4) governs sampling and analysis of waste and produced fluids. Under this Rule, the Director may 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. In these special circumstances, operators will have to submit sampling protocols for approval. Staff estimates this requirement will apply to 50 locations per year and cost industry approximately $15,000 per year.

Finally, Rule 915.f governs remediation projects in progress at the time the 800/900/1200 Mission Change Rules become effective. Operators of these 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. Staff anticipates that for about five percent of the approximately 1,360 active remediations, operators will submit a request to comply with prior Table 910-1. This will cost operators $500 per project, resulting in a total one-time cost to industry of $34,000.

($ Benefit)

Staff also anticipates that industry will receive quantifiable benefits to offset some of the costs associated with Rule 915. First, as a result of Rule 915.b's requirement to provide a detailed reclamation plan for those materials with elevated concentrations operators may leave in situ, operators will likely reduce monetary payouts to landowners following successful reclamation. Due to the reclamation plan, sites will also achieve reclamation faster, requiring less work by operators to be done after returning the site to surface owners. Staff anticipates that at the 100 sites requiring this type of reclamation plan, operators will avoid spending between $80 to $6,700 per project. This results in an annual benefit to industry between $8,000 and $670,000. **Table 8** provides additional detail for the analysis of operator avoided spending.

Next, Staff assumes that if operators pursue sampling based on a modified list of contaminants as provided for in Rule 915.e.(3).C, sampling protocols on large remediations could be reduced. Staff estimates this could apply at five locations per year and save operators $45 per sample at a rate of 50 samples per excavation. This results in an annual benefit to industry of $11,250.

Finally, Staff anticipates that as a result of Rule 915.f's provision allowing operators to request permission to comply with prior Table 910-1 for active remediation projects, operators may reduce remediation costs on selected legacy projects. Staff estimates that this will apply at 2.5% of the approximately 1,360 active remediations, saving operators between $500 and $50,000 per project. This results in a total one-time benefit to industry between $17,000 and $1,700,000.

(Qualitative)

Staff also assumes there will be qualitative benefits associated with Rule 915. Due to Rule 915.c's requirement to adhere to groundwater cleanup concentrations contained in Table 915-1, contamination of groundwater will be avoided, protecting public health and the environment. In addition, public trust in industry and confidence in regulatory outcomes will increase. The public will also gain confidence knowing that the quality of more water sources will be in compliance with the standards and classifications set forth in WQCC Regulation 41, resulting in both short- and long-term benefits.

Staff also anticipates that Rule 915.e.(3).B's requirement that operators immediately collect samples prior to evacuating contaminated groundwater will increase public trust in industry and enhance confidence in regulatory outcomes. The public will gain confidence that groundwater is being appropriately monitored and remediated in compliance with the standards set forth in Table 915-1. This has both short- and long-term benefits.

Staff expects that Rule 915.e.(4)'s requirement to obtain approval for and perform additional sampling of waste and produced fluids in certain circumstances will result in benefits to both industry and the public. Industry will achieve better site characterization and cleanup and public trust in industry or confidence in regulatory outcomes will increase with additional sampling. This has both short- and long-term benefits.

Table 8 – Rule 915.c Impact Calculation Detail

impact scenario / item	unit	low value	high value
INDUSTRY BENEFIT			
Crop Loss Following Oil and Gas Location Reclamation			
First Year	percent loss	100%	100%
Second Year	percent loss	50%	50%
Third Year	percent loss	25%	25%
Crop Value - Corn			
Yield	bushels per acre	168.0	168.0
Price	2020$ / bushel	$3.245	$3.245
Value	2020$	$545	$545
Crop Value - Wheat			
Yield	bushels per acre	37.1	37.1
Price	2020$ / bushel	$5.100	$5.100
Value	2020$	$189	$189
Three Year Avoided Operator Payout to Surface Owner for Crop Loss: Low = Wheat, High = Corn	**2020$ per acre**	**$331**	**$954**
Size of Oil and Gas Location for Reclamation	**acres**	**0.25**	**7.00**
Total Three Year Avoided Payout to Surface Owner (rounded)	2020$	$80	$6,700
Locations Where Reclamation is Successful Due to New Rule	locations per year	100	100
Subtotal, Total Benefit	**2020$ per year**	**$8,000**	**$670,000**

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur costs associated with Rule 915. Environmental Staff anticipates that Rule 915.a will require Staff to devote resources to reviewing each site to determine which cleanup standards apply. Thus, review of additional Form 19s will be necessary. Staff estimates that this requirement will apply to 550 spills per year and that Staff will spend an additional 0.25 hours per Form 19. This results in an annual cost of 0.066 FTE.

Next, Staff anticipates that Rule 915.b will require additional review of reclamation plans submitted by operators to address materials with elevated concentrations left in situ. Staff anticipates they will need to review reclamation progress at 100 sites per year and estimates that two hours will be spent per project. This results in an annual cost of 0.096 FTE.

Rule 915.c will also require Environmental Staff to review additional Form 27s as a result of projects affected by the well monitoring requirement. Staff anticipates this will apply at 550 projects and require four additional Form 27s at those sites per year. Staff estimates spending an additional 10 minutes on each Form 27, resulting in an annual cost of 0.176 FTE.

As a result of Rule 915.e.(3).B, Environmental Staff anticipates additional time will be spent reviewing Form 27s affected by groundwater analytics requirements. Staff estimates this will apply to 20 locations per year and require four hours of review per location. This results in an annual cost of 0.038 FTE.

Environmental Staff expects to spend an additional two hours per location reviewing sampling proposals and sampling data reports that are submitted in compliance with Rule 915.e.(3).C. Staff estimates this requirement will apply at five locations per year, resulting in an annual increased workload of 0.005 FTE.

Environmental Staff also expects to spend an additional one hour per location reviewing sampling proposals and sampling data reports that are submitted in compliance with Rule 915.e.(4). Staff estimates this requirement will apply at 50 locations per year, resulting in an added workload of 0.024 FTE.

Finally, Environmental Staff expects to spend an additional half hour reviewing each additional Form 19 or Form 27 submitted by an operator requesting permission to comply with the standards found in previous Table 910-1 for legacy remediation projects. This will apply at 70 locations one time, resulting in an added workload of 0.017 FTE.

(FTE Benefit) Staff also assumes it will incur benefits to offset some of the costs associated with Rule 915. Due to Rule 915.b's requirement to submit reclamation plans at locations where materials with elevated concentrations are left in situ, Staff expects it will receive and process fewer complaints concerning incomplete projects. This will likely occur at 10%, or 10, of the affected projects per year. Staff will save three hours per complaint, resulting in an annual benefit of 0.014 FTE.

Staff expects that the information now found in Table 915-1 will provide Environmental and Reclamation Staff with additional clarity and help operators and Staff come to agreement on final remediation and reclamation projects. Staff assumes that the specific standards found in Table 915-1 will save five hours of review per project and apply at 70 projects per year. This results in an annual benefit of 0.168 FTE.

($ Benefit) Finally, Staff anticipates that there will be a monetary benefit associated with Rule 910.e.(3).B. Ensuring operators clean up impacts to groundwater prevents future orphaned well projects, which may be discovered after project closure due to land development. Staff estimates this could save $50,000 per orphaned well project avoided. This could apply to one orphaned well project per year, yielding a $50,000 benefit to the State.

RULE(S) FOR WHICH NO COSTS OR BENEFITS ARE IMPLICATED

Of the 15 rules contained in the 900 Series, only two rules had no quantifiable or qualitative costs or benefits. These rules were created or amended to: comport with statutory requirements; to streamline processes; or to make other non-substantive edits. Accordingly, no measurable costs or benefits to any relevant party, either qualitative or quantitative, were determined to be present. For further explanation of these rules, refer to the Statement of Basis and Purpose.

- **Rule 906** – Management of Non-E&P Waste
- **Rule 914** – Criteria to Establish Points of Compliance

TWO ALTERNATIVES CONSIDERED IN THE 900 SERIES

Staff considered an alternative approach to the requirements proposed in subparts **b.(1)** and **(2)**, **c.(2)**, and **d.(1)** and **(3)** of **Rule 903** – Venting or Flaring Natural Gas. These requirements concern the reduction of venting and flaring activities at new and existing wells during drilling, completion, and production operations. Instead of allowing operators the flexibility to choose the technology that would be most appropriate to reduce or eliminate venting and flaring from each specific oil and gas location, Staff considered identifying a specific list of technologies that industry could choose from in order to comply with the directives set forth in these Rules. Some stakeholders suggested that it would be prudent for Staff to codify a list of acceptable technologies in order to improve clarity and ensure regulatory certainty. However, Staff anticipates that this approach would likely result in equivalent public health and environmental protections, while resulting in greater costs to both comply with and enforce these Rules.

Industry would see higher costs and Staff would experience increased workload if Rule 903 set forth a list of specific technologies that operators must use in order to limit venting and flaring. Staff has already explained that many of the options available to reduce venting and flaring could be fairly costly in some circumstances, particularly if an operator chooses to capture gas in a gathering system in an area that does not have existing pipeline capacity. However, it is difficult to estimate the exact cost impact to industry because Rule 903 allows operators the flexibility in determining a control technology or method to reduce venting and flaring by capturing gas and beneficially reusing it onsite or directing it to a sales pipeline. If the Rules were to specify that only certain technologies were available for use, operators would then be limited to technologies that may or may not effectively serve their needs at each oil and gas location. This approach could result in more natural gas wasted due to venting and flaring than under the Rule as currently proposed, because operators restrained by the listed options might be unable to utilize the specific technology available for each specific oil and gas location and might seek a variance to allow continued venting or flaring of the natural gas as a result.

The Rule as currently proposed anticipates FTE benefits with no added cost to the Commission. If a list of acceptable technologies were provided in Rule 903, Staff could see an increase in workload because more time would be required to consult with operators regarding the listed technologies. Identifying a list of specific technologies also fails to take into account that technology changes over time. The ability to tailor a control technology to a location's specific need is a qualitative benefit to operators that cannot be overlooked. Accordingly, Staff did not adopt this alternative, recognizing the efficiencies provided by a flexible approach to best available technologies.

Staff also considered not proposing **Rule 912.f** and instead continuing the current practice of searching the Commission's database each time it was necessary to determine ownership of a facility that has been transferred. By continuing the status quo, industry would save time and money by not having to task technical staff or a consultant with preparing and submitting a supplemental Form 19 upon transfer of ownership subject to an approved Form 9. However, this approach would result in Staff continuing to use substantial resources to continue searching for this type of information in its database. It would also eliminate one of the largest quantifiable benefits to Staff in reduced FTE provided by the 800/900/1200 Mission Change Rulemaking. Accordingly, Staff decided a "no action" alternative of maintaining the status quo in which new Form 19s are not filed upon transfer of operatorship was not appropriate. Because transfers of operatorship that involve active Form 19 spill reports may result in delays in cleaning up spills and thus more extensive environmental contamination, Staff believes that updating Form 19s upon transfer of operatorship will provide significant environmental benefits that align with SB 19-181's changes to the Commission's mission and statutory authority.

1200 SERIES: PROTECTION OF WILDLIFE RESOURCES
DETAILED DESCRIPTION OF COSTS AND BENEFITS

OVERVIEW OF REGULATORY CHANGES AND STATUTORY FOUNDATION

The 1200 Series governs the Commission's wildlife rules. The 1200 Series fulfills the Commission's statutory duty "to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources" and "protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations." C.R.S. § 34-60-106(2.5). The passage of SB 19-181 necessitated an update of this Rule Series in order to fully implement the legislation's 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, SB 19-191 modified the mitigation requirements appropriate for permit conditions in the habitat stewardship rules. C.R.S. § 34-60-128(3)(b). As a result, the 100-Series definitions now define the following: compensatory mitigation plan, wildlife mitigation plan, and wildlife protection plan. Second, the legislation clarified the hierarchy for minimizing adverse 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). The 100-Series definitions now include definitions for four important terms found in the 1200 Series: avoid adverse impacts, minimize adverse impacts, mitigate adverse impacts, and unavoidable adverse impacts.

Complimentary to the hierarchy is SB 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). This is reflected in Rule 304.b, which is analyzed below and includes the Commission's requirements for an alternative location analysis when wildlife resources may be impacted. Many of the other updates to the 1200 Series address SB 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). Organizationally, Staff tried to locate most of the process-oriented rules in the 300 Series with the 1200 Series providing more of the substance.

Staff determined that all the costs and benefits estimated and described below, considered separately or combined, will have no measurable impacts on job creation or the economy because many of the items that will incur costs will be absorbed by current employees. In addition, Staff believes that the proposed changes to the 1200 Series were the least costly way for the Commission to effectively comply with the General Assembly's mandates in SB 19-181. Staff also believes that, despite the additional net cost imposed on industry, the importance of the short- and long-term qualitative benefits to the industry and community warrant the changes to the 1200 Series because of the protections the rules provide to public health, safety, welfare, the environment, and wildlife resources.

RULES FOR WHICH COSTS AND BENEFITS ARE IMPLICATED

Table 9 (below) compiles all quantified costs and benefits to industry, communities, and wildlife resources that are expected after the 1200 Series rules are implemented. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series. Staff expect a wide spectrum of impacts on a per rule basis, from an annual recurring benefit to communities and wildlife of $0.66 million to an annual recurring cost on industry of $1.1 million.

Table 9 – 1200 Series Industry, Communities, and Wildlife Impact Detail

rule	impact	low	high	type
304.b	Cost to Industry	-$12,300	-$123,000	annual
309.e	Cost to Industry	-$255,000	-$490,500	annual
1201.a	Cost to Industry	-$125,000	-$250,000	annual
1201.b	Cost to Industry	-$40,000	-$840,000	annual
1202.d	Benefit to Communities and Wildlife	$660,000	$660,000	annual

1203.c	Cost to Industry	-$1,072,500	-$1,100,000	annual
1203.c	Cost to Industry	-$30,000	-$200,000	annual
1203.d	Cost to Industry	$0	-$174,000	annual
1203.d	Cost to Industry	$0	-$313,200	annual

Notes:
(i) All figures are estimates and expressed in 2020 dollars or FTE.
(ii) The analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).

Table 10 (below) details all quantifiable impacts on State Government that are expected after the 1200 Series rules are implemented. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series.

Staff expect a wide spectrum of workload impacts on a per rule basis, from a 0.60 FTE benefit, or reduction in State agency ongoing staffing, to a 1.92 FTE cost or increase to State agency ongoing staffing.

Table 10 – 1200 Series State Government Impact Detail

rule	impact	low	High	type
304.b	Cost to COGCC	0.020	0.099	annual FTE
304.b	Cost to CPW	0.020	0.099	annual FTE
309.e	Cost to CPW	0.163	0.196	annual FTE
309.e	Cost to CPW	0.780	0.983	annual FTE
309.e.2(B) to (F)	Cost to CPW	0.029	0.120	annual FTE
1201.a	Cost to COGCC	0.319	1.308	annual FTE
1201.a	Benefit to CPW	-0.080	-0.409	annual FTE
1201.b	Cost to CPW	0.031	0.040	annual FTE
1203.c	Cost to CPW	0.750	0.769	annual FTE
1203.c	Cost to CPW	0.058	0.115	annual FTE
1203.d	Cost to COGCC	0.000	0.034	annual FTE
1203.d	Cost to CPW	0.000	0.034	annual FTE

1203.d	Cost to CPW	0.000	0.404	annual FTE

Notes:
(i) All figures are estimates and expressed in 2020 dollars or FTE.
(ii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).
(iii) Net staffing reflects additional staff workload (cost impact), offset by reduced staff workload (benefit impact), caused by rule changes.
(iv) COGCC = Colorado Oil and Gas Conservation Commission. CPW = Colorado Parks and Wildlife. Both agencies are in the Colorado Department of Natural Resources.

Table 11 (below) summarizes all quantified impacts to all parties that are expected after the 1200 Series rules are implemented. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the series.

Overall quantified impacts to industry show a cost between $1.53 and $3.49 million annually. Communities and wildlife, as Colorado maintains its big game hunting economy, will benefit each year by $0.66 million. Overall impacts to State Government, both CPW and the Commission, indicate ongoing costs net of benefits (resulting in a workload increase) between 1.76 and 4.12 FTE.

Table 11 – 1200 Series Summary of Impacts

impact	low	high	type
Industry, Communities, and Wildlife			
Cost to Industry	-$1,534,800	-$3,490,700	annual
Benefit to Communities and Wildlife	$660,000	$660,000	annual
Cost Net of Benefit	**-$874,800**	**-$2,830,700**	**annual**
State Government			
Cost to State Government	2.17	4.20	annual FTE
Benefit to State Government	-0.41	-0.08	annual FTE
Cost Net of Benefit	**1.76**	**4.12**	**annual FTE**

Notes:
(i) All figures are estimates and expressed in 2020 dollars or FTE.
(ii) The analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 10 to 20 year averages when available).
(iv) Net staffing reflects additional staff workload (a cost), offset by reduced staff workload (a benefit), caused by rule changes.

Rule 304.b – Form 2A: Oil and Gas Location Assessment Application, Alternative Location Analysis

Rule 304.b.(2).A.iv sets forth the information requirements for a proposed location that is within high priority habitat for wildlife. This specific subset of Rule 304 was not previously analyzed in the 200–600 Cost-Benefit Analysis, because the Commission determined it would be more appropriate to adopt this Rule and address its impacts along with the 1200 Series. While many of the Commission's 1200 Series Rules provide mechanisms to minimize and mitigate adverse impacts to wildlife, alternative location analyses are the most important tool available to avoid adverse impacts to wildlife by identifying appropriate facility siting.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that industry will incur costs associated with Rule 304.b.(2).A.iv. First, the Rule requires operators to perform an alternative location analysis when a proposed oil and gas location is within high priority habitat. 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. In these instances, CPW may waive the requirement for an operator to conduct the alternative location analysis. Staff estimates that the requirement to perform an alternative location analysis will apply at 82 proposed oil and gas locations, or Form 2As, per year and that an operator's technical staff or consultant will spend between one and 10 hours on each analysis. This results in a cost to industry between $12,300 and $123,000 annually.

(Qualitative) Staff also assumes that Rule 304.b.(2).A.iv will result in qualitative benefits to industry and the community. First, due to the Rule's alternative location analysis requirement for proposed oil and gas locations within high priority habitat, operators will benefit from regulatory certainty because this type of analysis will not be required outside of high priority habitat areas, which will incentivize operators to propose oil and gas locations outside of high priority habitat. In addition, with the knowledge imparted by the alternative location analysis, operators will be able to fully comprehend and avoid impacts of oil and gas operations and mineral development on sensitive species and habitat. This has both short- and long-term benefits for operators' ability to plan oil and gas locations.

Benefits from this Rule will also flow to the community and wildlife species. Since the requirement of an alternative location analysis may dissuade some operators from siting proposed oil and gas operations within high priority habitat areas, those locations may remain undeveloped. As a result, wildlife species will experience less disruption during the most critical times of their life cycles (e.g., calving season or winter ranges), and the public will be able to enjoy the associated wildlife values. Avoiding development in high priority habitat also benefits the ecosystems that wildlife rely upon and will result in less habitat fragmentation, which is crucial for the long term robustness of wildlife species. Staff expects these benefits will be both short- and long-term.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur a cost to implement Rule 304.b.(2).A.iv. Both Commission and CPW Staff expect to spend a half hour to two hours per Form 2A to review wildlife elements of the alternative location analysis submitted by the operator. This will apply at 82 proposed locations per year and result in Commission and CPW Staff each incurring a cost between 0.020 and 0.099 FTE.

(FTE Benefit) Staff did not identify any FTE benefits associated with Rule 304.b.(2).A.iv.

Rule 309.e – Consultation, Colorado Parks and Wildlife

Rule 309.e specifies the purpose and process for consultation with CPW and was not previously analyzed under the 200–600 Series Mission Change Rulemaking Cost Benefit Analysis. Rule 309.e expands the Commission's prior requirements for operators to consult with CPW when a proposed oil and gas location implicates a potential impact to wildlife resources associated with high priority habitats. The Rule details that consultations may also be appropriate when, in certain circumstances outside the oil and gas location permitting context, the Commission or its Staff must make a decision that implicates wildlife resources. There are also circumstances in which CPW consultation may not be necessary—largely attributable to early coordination between the operator and CPW—and the Rule therefore allows CPW to waive consultation at any point. Rule 309.e also contains provisions addressing the surface owner's role in the consultation process, as required by statute. C.R.S. § 34-60-128(3)(b).

- **Impacts on Industry and the Community**

($ Cost) Staff anticipates there will be costs to industry associated with Rule 309.e.(2). First, Staff assumes operators will incur general costs beyond those they would have incurred under the Commission's prior Rules, resulting from Rule 309.e.(2)'s comprehensive requirement to consult with CPW and surface owners in certain situations involving high priority habitat. There are important objectives associated with this consultation requirement. First, the requirement helps to fulfill the Commission's mission and statutory requirement to avoid, minimize, and otherwise mitigate adverse impacts to wildlife resources associated with oil and gas development. Most importantly, the consultation will allow the Commission and the operator to obtain the best available information from CPW regarding potential impacts to wildlife resources and proceed accordingly. Staff estimates that at applicable locations, operators will spend up to 20 to 30 hours per location consulting with CPW and that this requirement will apply to between 85 and 109 Form 2As per year. This results in an annual cost to industry between $255,000 and $490,500.

Staff also assumes a cost to industry under Rule 309.e.(5).B. Under the provisions of this Rule, CPW may recommend that the Commission deny an Oil and Gas Development Plan, Wildlife Protection Plan, Wildlife Mitigation Plan, Compensatory Mitigation Plan, or Comprehensive Area Plan due to reasonably foreseeable risks to wildlife resources that cannot be avoided, minimized, or mitigated to the extent necessary to protect these resources from oil and gas operations. If CPW recommends denial of a proposed permit or plan, two things may happen: the Director will agree with CPW and also recommend denial, or the Director will disagree with CPW's recommendation. In both cases, the results of the consultation will be elevated to the Commission for a decision, and the Commission may therefore deny a permit application based on such a recommendation. Staff anticipates that if an operator is denied a permit based on the wildlife analysis submitted as part of their Form 2A, the operator will accrue expenses in pursuit of solutions that satisfy CPW's and the Commission's concerns. This could cost an additional 50 to 100% of the original plan cost. Staff expects that this situation will happen very rarely and does not have sufficient data to estimate the monetary impact.

(Qualitative) Staff expects that operators will see qualitative benefits as a result of Rule 309.e.(2). Due to the Rule's general requirement to engage in consultation with CPW regarding high priority habitat areas, operators will understand wildlife and habitat expectations earlier in the process and have regulatory certainty. Operators will avoid the additional cost and project development delays that can occur under the prior Rules when sensitive species and habitat constraints were identified later in the course of permitting a project. In addition, the Commission and CPW will coordinate consultations implicating federally listed species and their critical habitat with the appropriate federal agency, thereby reducing the costs borne by industry from compliance with Federal rules related to federally listed species. These industry benefits will be both short- and long-term.

The consultation requirement in Rule 309.e.(2) and the CPW recommendation provision in Rule 309.e.(5).B will also benefit wildlife species and ecosystems, as well as public enjoyment of associated wildlife values. By understanding the potential impacts to high priority habitat areas that result from oil and gas locations, the Commission can make decisions that will avoid impacts to individual species and their habitat. This will assist in ensuring healthy and sustainable populations and ecosystems, and reduce habitat fragmentation, resulting in short- and long-term benefits.

- **Impacts on State Government**

(FTE Cost) Staff expects to incur costs associated with Rule 309.e.(2). First, CPW Staff assumes it will spend additional time completing consultations with operators on proposed locations in no surface occupancy ("NSO") areas. Under the Rule, a surface owner may 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; however, a surface owner cannot prevent the Commission from requiring compensatory mitigation or offsite wildlife mitigation efforts as part of a Form 2A condition of approval. CPW Staff estimates that between 20 and 24 hours per Form 2A will be spent completing NSO consultations and that this requirement will apply to 17 Form 2As per year. This results in an annual cost to CPW between 0.163 and 0.196 FTE.

CPW Staff also expects to incur costs as a result the consultation requirement on proposed locations in high priority habitat areas found in Rule 309.e.(2).A. Staff anticipates that between 80 to 84 proposed locations annually will involve high priority habitat areas. Staff expects to spend between 20 to 24 additional hours on each Form 2A in this category, resulting in an annual cost to CPW between 0.780 and 0.983 FTE.

Next, Rule 309.e.(2).B–F will likely require CPW Staff to complete additional consultations with operators where: the area falls within federally designated critical habitat for threatened or endangered species or an existing conservation easement; CPW requests consultation or because consultation is necessary to avoid, minimize, or mitigate adverse impacts; the operator seeks a variance from the 1200 Series Rules or permit conditions related to wildlife protection; or the Director determines a consultation is necessary. CPW Staff anticipates spending between 20 to 24 additional hours on each Form 2A, variance request, oil and gas development plan, or comprehensive area plan falling within the scope of Rule 309.e.(2).B–F. Staff further estimates that this will apply to between three and 10 Form 2As or other applications per year, resulting in an annual increase in workload to CPW between 0.029 and 0.120 FTE.

Finally, in the rare circumstance where the Commission denies a permit under Rule 309.e.(5).B, both Commission and CPW Staff expect to incur FTE costs. This provision is intended to emphasize the importance of cooperative analysis and consultation between agencies to achieve necessary wildlife resource protection. Both Commission and CPW Staff expect to spend time and effort consulting with operators, working with operators to correct of modify applications, and reviewing replacement plan documentation. In the unusual case where there may be disagreement between CPW and the Director, there may be an additional cost borne by CPW to present at the Commission hearing. This will result in additional FTE time spent annually, but Staff does not have sufficient data to estimate the FTE cost.

(FTE Benefit) Staff also identified benefits associated with Rule 309.e.(2).A. First, the Rule's consultation requirement will result in time savings for both CPW and the Commission. As a result of planning, fewer subsequent management plans will be required. It is therefore less likely that either the federal government or CPW will list sensitive species as threatened or endangered in the future because there will be less disruption and fragmentation of their habitat. While this will likely result in an annual time savings, Staff does not have sufficient data to estimate such FTE benefit.

In addition, Staff anticipates a long-term benefit as a result of Rule 309.e.(2).A. Due to increased consultation between CPW and operators, the Commission will be able to learn from each consultation and more fully comprehend which species and habitats are a concern prior to approving a Form 2A. This knowledge should bring added efficiency to the regulatory process since CPW will be involved at the outset of the proposed location process and will likely not intervene with high priority habitat concerns later in the process assuming CPW's concerns are carried forward. While this will save Staff time each year, Staff does not have sufficient data to quantify the FTE benefit.

Rule 1201 – Wildlife Plans

Rule 1201 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. Subparts a and b describe generally the two planning tools the Commission expects operators to utilize: Wildlife Protection Plans and Wildlife Mitigation Plans.

- **Impacts on Industry and the Community**

($ Cost) Staff expects that industry will incur costs as a result of Rule 1201. First, Rule 1201.a requires operators of proposed oil and gas operations on new or amended oil and gas locations outside of high priority habitat to submit a Wildlife Protection Plan ("WPP"). Each WPP must include a description of the Rule 1202.a operating requirements applicable to the oil and gas location and may address multiple oil and gas locations if supplemental site-specific information is provided as needed. WPPs do not require CPW consultation or approval. Staff assumes that this requirement will apply at 166 to 170 proposed oil and gas locations, or Form 2As, per year and will cost operators between $500 to $1,000 per WPP. This results in a cost to industry between $83,000 and $170,000 annually.

Under Rule 1201.b, operators of proposed oil and gas operations on new or amended oil and gas locations within high priority habitat are required to submit a Wildlife Mitigation Plan ("WMP"). Each WMP must include a description of the Rule 1202.a operating requirements applicable to the oil and gas location along with additional operating and mitigation requirements. Consultation with CPW is required for approval under this Rule. Staff assumes that this requirement will apply at between 80 and 84 proposed oil and gas locations per year and will cost operators between $500 and $10,000 per WMP. This results in an annual cost to industry between $40,000 and $840,000.

(Qualitative) Next, Staff anticipates there will be qualitative benefits associated with Rule 1201. As a result of Rule 1201.a and b's requirement to submit a WPP or WMP for each proposed oil and gas location, public trust in industry will increase as protections are implemented for certain species and habitats. Industry will also benefit from regulatory certainty as these planning processes are formalized. This has both short- and long-term benefits.

In addition, Staff assumes that Rule 1201.a's requirement to submit a WPP will result in benefits to the community. Because the WPP promotes conservation and protection of wildlife species and habitats outside of high priority habitat areas, the requirement will lead to an overall reduction in species mortality rates and habitat loss, decrease in human wildlife conflicts, maintenance of populations, avoidance of future listing under the Endangered Species Act, and minimization of terrestrial and aquatic habitat degradation. While these results are difficult to quantify, they will have both short- and long-term benefits.

Finally, Staff expects that Rule 1201.b's requirement to submit a WMP for each proposed oil and gas location within high priority habitat facilitates an analysis regarding the potential impacts on wildlife resources on a scale commensurate with the impact. This will result in an increase to beneficial outcomes for individual wildlife species and their habitat by reducing human-wildlife conflicts, direct mortality, terrestrial and aquatic habitat degradation, and offsetting residual unavoidable impacts. Staff expects these benefits to be both short- and long-term.

- **Impacts on State Government**

(FTE Cost) Staff assumes it will incur costs resulting from Rule 1201. The requirement under Rule 1201.a. for each operator to submit a WPP will require Commission Staff to review each submission and plan updates accordingly. Staff estimates this task will require between four and sixteen hours of review per WPP. The WPP requirement will apply to approximately 166 to 170 proposed oil and gas locations per year, resulting in a cost between 0.319 and 1.308 FTE annually.

Rule 1201.b's requirement to submit a WMP for those proposed oil and gas locations within high priority habitat will require CPW Staff to spend additional time working with operators to develop their plans. Staff estimates that this will apply only to 5% of the 80 to

84 Form 2As that require a WMP, as Staff will have accounted for much of the time spent conferring with operators as part of the consultation requirement in Rule 309.e. As a result, CPW Staff anticipates an annual cost between 0.031 and 0.040 FTE.

(FTE Benefit) Staff anticipates that there will be FTE benefits resulting from Rule 1201. The WPP requirement in Rule 1201.a will likely reduce the workload of CPW Staff because less time will be spent on recovery efforts as steps were taken up front to promote species and habitat protection. CPW Staff estimates that between one and five hours will be saved as a result of each WPP, which applies to 166 to 170 Form 2As per year. This results in an FTE benefit between 0.080 and 0.409 FTE annually.

Finally, CPW Staff expects to realize efficiencies as they go through the process of assisting operators with WMPs and considering potential impacts to high priority habitat as required by Rule 1201.b. Staff assumes that this will apply at 5% of the 80 to 84 Form 2As that require a WMP but does not have additional sufficient data to quantify a FTE benefit.

Rule 1202 – Operating Requirements

In Rule 1202, Staff updated, adapted, and added to the operating requirements and restrictions relating to protection of wildlife. Generally, the Rule requires operators to take appropriate measures to minimize impacts of oil and gas development to wildlife resources. Rule 1202.a includes requirements that apply statewide and Rule 1202.b articulates additional operating requirements that apply to operations within high priority habitat. Rules 1202.c and d include modifications to the Commission's prior restricted surface occupancy and sensitive wildlife habitat Rules. These updates were necessary to meet SB 19-181's changes to the Commission's mission and statutory authority.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that there will be costs to industry associated with Rule 1202. First, Rule 1202.a identifies operating requirements that apply to all oil and gas locations statewide. The Commission and CPW determined that these are appropriate measures to minimize impacts to wildlife resources. These practices will be described in the operator's wildlife protection plan. Many of these requirements were included in prior Rules 1203 and 1204 and applied only in certain areas. Changes that will involve a cost to industry are addressed below.

  - Rule 1202.a now includes a requirement for operators to fence and net or install other CPW-approved exclusion devices on new and existing drilling pits, production pits, and other pits associated with oil and gas operations that are intended to contain fluids. The fencing and netting or other CPW-approved exclusion device must be installed within five days after the cessation of active drilling and completion activities and maintained until removed. This requirement was necessary to implement SB 19-181's directive to minimize adverse and potentially adverse impacts of oil and gas activities on wildlife resources. Uncovered pits pose a significant threat to wildlife, particularly migratory birds, and numerous studies, as well as each agency's regulatory experience, document that uncovered pits are the leading cause of avian mortality associated with oil and gas development. Staff did not estimate the total cost of fencing and netting existing pits because of too many variables—some of which Staff lacks reliable information about—that influence the cost of fencing and netting pits. Staff has data available about the number of pits statewide and can examine that information for specific geographic areas. For example, Staff can identify the number of pits in the Piceance Basin and the Raton Basin, or the number of pits in Yuma County or San Juan County. While Staff has a general sense of the size of pits in various basins, it does not currently have data available about the size of each pit statewide. Thus, as a general principle, Staff is aware that pits in the Eastern Plains are typically much larger than pits on the Western Slope. However, not all pits in a specific basin adhere to these general trends, and Staff does not have exact size data available for many of the 3,357 existing pits statewide that would be subject to this Rule. The size of a pit is one of the most important variables for determining the cost of fencing and netting a pit. Staff estimates that the cost of installing exclusion devices such as fences or nets could cost operators anywhere between $5,000 and $100,000 per pit, although very few pits would be likely be large enough to fall in the upper range of this cost estimates. Additionally, Staff does not have data available to estimate how many of those 3,357 existing pits statewide are not already fenced and/or netted, because many pits already are fenced and/or netted to exclude wildlife and livestock. In Staff's experience, it is generally more common for pits to be fenced and/or netted on the Western Slope than on the Eastern Plains, but again there are many exceptions to this general trend. Accordingly, Staff does not have sufficient data to estimate the number of existing pits that would be required to install nets and/or fencing, or the one-time cost associated with this change. Although Staff can more reliably estimate the likely number of new pits per year, Staff does not have sufficient information to estimate the average size or range of sizes of those pits, and therefore could similarly not estimate a cost associated with this change for new pits.

- Next, Rule 1202.a requires operators to install wildlife escape ramps at a minimum of one ramp per ¼ mile of trench for trenches that are left open for more than five consecutive days and now applies statewide. This change was necessary in order to minimize the adverse impacts of oil and gas locations on wildlife resources. Staff estimates that it will cost operators $1,000 per ramp or per ¼ mile of trench to comply with this requirement. However, Staff does not have sufficient data to estimate the number of trenches that would be affected per year or the annual cost associated with this change.
- Rule 1202.a was also updated to require operators to use CPW-recommended fence designs when consistent with the approval of a surface owner and any other local government requirements at locations statewide. Staff estimates that this will result in a cost to operators of $13.50 per linear foot of fencing on an average 1,800-foot perimeter for each five acre well pad, totaling about $25,205 per location. However, Staff does not have sufficient data about how many locations per year would incur additional fencing costs to comply with this requirement, and thus could not estimate the number of locations that would be affected per year or the annual cost associated with this requirement.

Rule 1202.b sets forth additional operating requirements that apply at all oil and gas locations in high priority habitats. Given the importance of this type of habitat, Staff 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. The requirements that will result in a cost to industry are listed below.

- Rule 1202.b now requires operators to bore, rather than trench, flowline and utility crossings of perennial streams identified as aquatic high priority habitat. Staff assumes that this requirement will apply each time a perennial stream is crossed by the construction of a flowline and that this could occur at five oil and gas locations each year. The requirement to bore will likely result in a 30% to 50% higher cost to operators. However, Staff does not have sufficient data about the number of utility crossings of perennial streams that will be constructed each year to estimate the annual cost associated with this requirement.
- In addition, Rule 1202.b includes the requirement for operators to treat drilling pits, production pits, and any other pit associated with oil and gas operations that provides a medium for breeding mosquitoes with control measures to prevent West Nile Virus in wildlife. This requirement now applies in high priority habitat. Staff estimates that it will cost between \$25 to \$50 per gallon of product necessary to treat liquids stored in pits. However, prior Rule 1203 applied the same requirement in sensitive habitat areas and restricted occupancy areas, and Staff does not have sufficient data to estimate whether any of the future locations proposed in high priority habitat would not have been in areas classified as sensitive habitat or restricted occupancy under the prior Rules, or whether any or how many of those operations will involve drilling pits, and therefore could not estimate the annual cost associated with this requirement.

Both Rules 1202.a and b include a provision exempting operators from compliance with the statewide or high priority habitat requirements if a signed waiver is obtained from CPW and a Form 4, Sundry Notice, or Form 2A, Oil and Gas Location Assessment, is approved documenting the relief. Staff estimates that operators will incur a cost of two hours to document each approved waiver using a Form 4 or Form 2A. However, Staff is unable to estimate the rates at which operators will request and receive waivers. Therefore, Staff does not have sufficient data to estimate an annual cost to industry.

Next, Rule 1202.c restricts operators from conducting any new ground disturbance and well work, including access road and pad construction, drilling and completion activities, and flowline/utility corridor clearing and installation in certain high priority habitat areas. The habitats listed in Rule 1202.c. are the most crucial wildlife habitats. Staff and CPW determined that for these wildlife resources, avoidance is the single most effective protection strategy. For certain time-sensitive activities and non-emergency workovers at existing locations, Staff has carved out exceptions that require prior Commission approval and consultation with CPW. Staff anticipates that it will cost operators between five and 10 days of delay per year in each situation where an operator must obtain Director approval and consult with CPW. However, Staff does not have sufficient data to estimate the number of locations that will be affected or the annual cost to industry associated with these potential delays.

Finally, Rule 1202.d requires operators to submit CPW-approved wildlife mitigation plans, or other CPW-approved conservation plans, whenever any proposed new location will cause the density of an oil and gas location to exceed one per square mile in a listed high priority habitat. Essentially, this Rule requires operators to evaluate whether to keep a location inside a high priority habitat or move the location elsewhere—a process also known as an alternative location analysis. Therefore, please refer to Rule 304.b for a more robust discussion of the cost involved with alternative location analyses.

($ Benefit) Staff assumes there will be monetary benefits resulting from Rule 1202. Local communities and wildlife will benefit from Rule 1202.c, as outdoor recreation opportunities are preserved. First, with respect to angling, the current Rules protect only "Gold Medal" streams or lakes and certain trout habitats from new ground disturbance and well work associated with oil and gas development with the use of restricted use occupancy areas. The new Rule broadens these protections to areas known as high priority habitats, which now include cutthroat trout designated crucial habitat, native aquatic species conservation waters, and sportfish management waters as listed in subsections Q–R. Staff estimates that local communities will benefit from these changes to the Commission's Rules, which will help preserve the positive economic impacts to the angling industry, which contributes an estimated $1.23 billion in total gross domestic product to Colorado's economy.[4] In addition to angling, Rule 1202.c will also benefit wildlife and bird watchers as it now protects the specific high priority habitats listed in subparts A–P and T of the Rule from new ground disturbances and well work. This will also contribute to preserving the positive economic benefits of wildlife watching, which is an industry that contributes to an estimated $1.07 billion in total gross domestic product to Colorado's economy.[5] Recreation-related spending by anglers and wildlife watchers will continue in these areas where resource value is sustained by the new Rule. This translates to potential income for businesses associated with angling and wildlife viewing opportunities (*e.g.*, guides, outfitters, processors, hotels, restaurants, and sporting stores).

Because operators will have to limit development density in high priority habitats, reduced habitat disturbance will benefit numerous wildlife species, including several big game species. As a result, the community will avoid a potential loss in direct economic benefits from spending by big game hunters. Absent Rule 1202.d, approximately 80 square miles, or 0.2%, of total State big game habitat would be impacted per year, potentially decreasing current or future year spending by hunters. Based on evidence available to CPW and Commission Staff on overall trends in spending by hunters, the proportionate impact on total big game hunting gross domestic product is $660,000. This amount is the annual benefit to the community if the 80 square miles under the new Rule is maintained as undisturbed big game habitat without impacts from development. Staff anticipates there will be additional quantitative benefits from reduced habitat disturbance of other species that also provide economic benefits from other uses of wildlife, such as birdwatching, but does not have sufficient data to quantify these benefits. **Table 12** (below) provides additional detail for the calculation.

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[4] *See* Colorado Parks and Wildlife and Southwick Associates, The 2017 Economic Contributions of Outdoor Recreation in Colorado: A Regional and County-Level Analysis at Appendix F (July 2018).
[5] *Id.*

Table 12 – Rule 1202.d Impact Calculation Detail

impact scenario / item	unit	low value	high value
COMMUNITIES AND WILDLIFE BENEFIT			
Total Land Area in Colorado That Supports Big Game Hunting[1]	square miles	40,927	40,927
Total Area Negatively Impacted by New Oil and Gas (O&G) Development, Current Rule Net of New Rule	square miles	80	80
Maximum Percent Loss from Area Impacted, Current Rule Net of New Rule	**percent**	**0.20%**	**0.20%**
Big Game Hunting GDP Contribution for Colorado[2]			
Residents	2020$ per year	$197,400,000	$197,400,000
Non Residents	2020$ per year	$138,600,000	$138,600,000
Total GDP Contribution	**2020$ per year**	**$336,000,000**	**$336,000,000**
Maximum Avoided Loss to State GDP from New O&G Development, Current Rule Net of New Rule	**2020$ per year**	**$660,000**	**$660,000**

Notes:

(1) Big game area in Colorado consists of mule deer severe winter range, mule deer winter concentration areas, mule deer migration corridors, elk severe winter range, elk winter concentration areas, elk migration corridors, elk production areas, pronghorn winter concentration areas, and pronghorn migration corridors.

(2) Colorado Parks and Wildlife and Southwick Associates, The 2017 Economic Contributions of Outdoor Recreation in Colorado: A Regional and County-Level Analysis at Appendix F (July 2018).

(Qualitative) Staff anticipates there will be qualitative benefits as a result of Rule 1202. Due to the statewide application of Rule 1202.a's requirements and the high priority habitat requirements in Rule 1202.b, aquatic resources will be afforded protections that will safeguard both the immediate area and provide downstream protections. Rule 1202.a will ensure that healthy waterways remain and angling opportunities are protected statewide. Rule 1202.b will protect perennial streams in aquatic high priority habitat and the passage of fish through structures, so that populations remain healthy, connected, and genetically viable. Both protections will in turn contribute to local revenues (*e.g.*, economic contributions by anglers). In addition, wildlife species and their habitats will also benefit from reduced human wildlife conflicts, direct and indirect mortality, and the degradation of both terrestrial and aquatic habitats. These Rules provide a more comprehensive and holistic approach to maintaining existing habitat and wildlife populations during oil and gas development throughout Colorado. Operators will benefit from compliance with these Rules because locations will see fewer adverse impacts to the environment and wildlife conflicts. In addition, industry will gain Commission, CPW, and public trust as being stewards of the landscape. These benefits will be both short- and long-term.

Additionally, Rule 1202.c's new development protections required for a fixed list of species and habitat will provide industry with regulatory certainty. Because the Rule exempts certain activities at existing locations following an approval and consultation process, operators will have the opportunity to learn more about best practices to minimize adverse impacts to wildlife resources. Industry will also gain Commission, CPW, and public trust as being stewards of the landscape. These benefits will be both short- and long-term.

Finally, as a result of the requirement in Rule 1202.d to limit development density in high priority habitat areas and submit wildlife management plans, industry will benefit from regulatory certainty. In addition, the community, and specifically wildlife, will see benefits. Limiting development density promotes maintenance of existing population levels, the protection of large tracts of undisturbed habitats, habitat effectiveness, and suitable habitat and distribution of the listed species. The prior Rules were designed to reduce impacts to species listed in Rule 1202.d, but those prior requirements could ultimately lead to a decrease in habitat effectiveness and wildlife populations. Thus, limiting the density of development, or requiring mitigation for habitat degradation that results from increased development density, results in short- and long-term benefits to planned industry investment and development.

- **Impacts on State Government**

(FTE Cost) Staff assumes there will be costs associated with Rule 1202. The requirements set forth in Rules 1202.a and b apply unless an operator requests a waiver. CPW Staff anticipates that it will spend between one and eight hours reviewing each waiver per year. However, Staff does not have sufficient data to quantify the number of waivers it may receive annually and therefore cannot quantify an FTE cost.

Rule 1202.c exempts certain non-emergency activities at existing facilities in the listed high priority habitat areas if an operator receives approval from the Director of the Commission and participates in a consultation with CPW. Both Commission and CPW Staff anticipate spending an additional hour each per exemption request per year. However, Staff does not have sufficient data to quantify the number of exemption requests it may receive annually and therefore cannot quantify an FTE cost.

(FTE Benefit)

Staff also identified benefits as a result of Rule 1202. First, CPW Staff anticipates that as a result of Rules 1202.a and b, less time will be spent addressing wildlife issues such as human wildlife conflicts, aquatic degradation, and mortality issues for birds, bats, and other wildlife that may have been previously impacted by pits at oil and gas locations. However, Staff does not have sufficient data to estimate the annual FTE benefit as a result of this Rule.

Rule 1203 – Compensatory Mitigation for Wildlife Resources

Staff created Rule 1203 to provide alternatives for operators to address compensatory mitigation for direct impacts or unavoidable adverse indirect impacts to high priority habitats through either performance of a compensatory mitigation plan or payment of a fee. The Rule details the elements that must be present in each compensatory mitigation project and specifies the fee that applies if an operator chooses not to conduct mitigation projects. 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.

- **Impacts on Industry and the Community**

($ Cost)

Staff assumes there will be costs to industry associated with Rule 1203. First, Rule 1203.a requires operators to complete compensatory mitigation to offset direct and unavoidable adverse impacts to high priority habitats unless an exception is granted by the Director. 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. This Rule requires mitigation of only those indirect adverse impacts that cannot be eliminated through the application of alternative location selection or other methods designed to avoid adverse impacts. Operators may achieve compliance with the Rule by completing, or causing to be completed, a Director- and CPW-approved project or by paying a habitat mitigation fee to CPW. In some cases, the payment of a fee may be the most effective and efficient way to accomplish compensatory mitigation and is an alternative compliance mechanism that operators may choose. Staff expects that in order to comply with Rule 1203.a, operators will incur costs to develop a compensatory mitigation plan and coordinating with Commission and CPW Staff for each impacted location. However, Staff does not have sufficient data to estimate the annual cost to industry as a result of Rule 1203.a.

Next, Rule 1203.b details the requirements for operators who opt to complete or cause to be completed compensatory mitigation. Operators must submit and receive approval for a Compensatory Mitigation Plan, which must contain certain elements listed in the Rule. Staff included the plan elements required in order to ensure effective projects with measurable results. Staff assumes that operators will incur two main costs associated with Rule 1203.b. First, operators will likely spend between $20,000 to $30,000 per project to set up compensatory mitigation projects to satisfy this Rule. Second, operators will incur costs to monitor and report progress in meeting the goals of their compensatory mitigation plans. This will likely cost between $3,750 and $5,000 per project, involving 25 to 30 hours per project per year. Since it is difficult to estimate how many times this option will be chosen instead of paying the mitigation fee, and in many instances paying the fee will be more practical than completing a mitigation project, Staff does not have sufficient data to estimate the annual cost to industry.

Under Rule 1203.c, an operator may comply with its obligation to mitigate direct impacts to wildlife caused by new ground disturbance within high priority habitat by paying a habitat mitigation fee to CPW. Staff included a tiered approach to the direct impact mitigation fee, imposing a flat fee on locations less than 11 acres and basing the fee on those locations above 11 acres on site-specific considerations and the results of a consultation with CPW. Staff took this approach based on the Commission's and CPW's overall experience understanding the impacts to wildlife resources associated with oil and gas locations that are less than 11 acres. In those cases, the imposition of a flat fee is more appropriate whereas for locations over 11 acres, it is suitable to require a more in-depth review to understand and mitigate impacts. Staff assumes that there will be two costs associated with Rule 1203.c, but that only one will apply depending on the acreage of a location within high priority habitat. For those locations that are less than 11 acres, operators will pay a flat fee of $13,750 per location and Staff estimates that this will likely apply to between 78 and 80 locations statewide per year. This results in an annual cost to industry between $1,072,500 and $1,100,000. However, for those locations that are more than 11 acres, Staff estimates that operators will incur costs between $15,000 and $50,000 per location and that this may apply to between two and four locations per year. This results in an annual cost to industry for locations greater than 11 acres between $30,000 and $200,000.

Finally, pursuant to Rule 1203.d, CPW may recommend to the Director whether compensatory mitigation is required to address the unavoidable adverse indirect impacts of habitat fragmentation caused by a proposed oil and gas development plan in high priority habitats with a density of oil and gas locations less than five per square mile. If the Director determines such compensatory mitigation is necessary, an operator may comply with its obligation under this Rule by completing a CPW-approved mitigation project or by paying a fee set by the Director based on CPW's estimate of costs reasonably necessary to complete compensatory mitigation. The fee estimate will be largely dependent on the type of high priority habitat that could be fragmented by increased well density, including the indirect habitat acreage necessary to prevent disruptions to the species at issue, and other conservation-related costs. The costs related to developing a compensatory mitigation plan have been discussed above in Rule 1203.b. If operators choose to complete a CPW-approved mitigation project, Staff estimates the cost will vary depending upon which type of habitat may be indirectly impacted by an oil and gas location. If a location impacts mule deer and other big game species habitat, the maximum indirect acreage affected is likely 120 acres. Based on a review of CPW-approved projects and their per acre costs, operators may pay between $179 and $725 per acre per location. Staff estimates that Rule 1203.d compensatory mitigation will be required at zero to two locations per year with impacts to big game species, resulting in an annual cost to industry of between $0 and $174,000. If a location impacts sage grouse, sharp-tailed grouse, or prairie chickens, the maximum indirect acreage affected is likely 36 acres. The same compensatory mitigation in CPW-approved projects costs between $179 and $725 per acre per location would also apply. Staff estimates that this category of compensatory mitigation will be required at zero to 12 locations per year, resulting in an annual cost to industry between $0 and $313,200. **Table 13** (below) provides additional detail on these calculations.

Table 13 – Rule 1203.d Impact Calculation Detail

impact scenario / item	unit	low value	high value
INDUSTRY COST			
Mule Deer and Other Big Game Species			
Form 2As Per Year That Trigger Indirect Impacts	locations per year	0	2
Maximum Habitat Acreage Affected by Indirect Impacts	acres	120	120
Compensatory Mitigation Cost Average	2020$ per acre	$179	$725
Subtotal, Total Cost	**2020$ per year**	**$0**	**$174,000**
Sage Grouse, Sharp-Tailed Grouse, and Prairie Chicken			
Form 2As Per Year That Trigger Indirect Impacts	locations per year	0	12
Maximum Habitat Acreage Affected by Indirect Impacts	acres	36	36
Compensatory Mitigation Cost Average	2020$ per acre	$179	$725
Subtotal, Total Cost	**2020$ per year**	**$0**	**$313,200**

(Qualitative) Staff anticipates there will be qualitative benefits associated with Rule 1203. First, by providing a choice between completing a mitigation project at an affected location or paying a habitat mitigation fee, Rule 1203.a will provide operators with flexibility to choose the most effective and efficient means to complete compensatory mitigation. Operators will also experience regulatory certainty and consistency knowing that compensatory mitigation will be required when locations impact high priority habitat areas. In some cases, operators may be able to plan ahead by banking mitigation credits through a CPW-approved habitat bank.

Wildlife species and communities will also see benefits from Rule 1203.a. Since industry will be required to complete compensatory mitigation for impacting high priority habitats, those habitat acreages should remain somewhat stable over time. Wildlife species will also be able to rely on less disturbance to critical habitats. This will also have a positive economic impact on communities depending on fees associated with wildlife, as the public—and specifically hunters, anglers, and birdwatchers—will have stable habitat acreages to access. These benefits will be both short- and long-term.

Next, communities and the public will likely benefit from Rule 1203.b. Communities could see an economic uptick from operators who choose to hire local professionals to work on mitigation projects in high priority habitat areas. In addition, the public will benefit from project transparency as the plans will allow a window into operators' progress on mitigation projects. These benefits will be both short- and long-term.

Wildlife and the public will also benefit from Rule 1203.c. Because operators will pay a habitat mitigation fee to CPW, the agency will be able to more directly employ its expertise and complete mitigation projects in high priority habitat on a timeline that is the most protective of species and habitats. The public will also benefit from more consistent wildlife protection that accompanies industry disturbance. These have both short- and long-term benefits.

Finally, operators, wildlife, and communities will see benefits from Rule 1203.d. Operators will experience regulatory certainty in the new development protections required for species affected by indirect impacts. In addition, wildlife and communities will benefit from industry mitigating the indirect impacts of oil and gas development for the same reasons discussed above for direct impacts.

- **Impacts on State Government**

(FTE Cost) Staff expects to incur costs as a result of Rule 1203. As a result of the compensatory mitigation requirement in Rule 1203.a, CPW Staff will have to coordinate review of each operator mitigation proposal with Commission Staff on a site-by-site basis, and vice versa. CPW Staff will also need to expand mitigation options by completing more habitat projects. While this will likely impact both agencies, Staff does not have sufficient data to estimate the annual FTE cost as a result of this Rule.

Rule 1203.b's requirements surrounding the specifics of compensatory mitigation plans will also result in costs to CPW and Commission Staff. First, CPW Staff expects to spend 14 to 25 additional hours reviewing each operator-led mitigation project submitted. Next, both CPW and Commission Staff assume that Staff from each agency will spend approximately five hours conferring on each operator-led mitigation project. Finally, CPW

Staff anticipates that it will spend between eight- and 16-hours reviewing monitoring and reporting on each operator-led project. However, Staff does not have sufficient data to estimate the annual FTE cost as a result of this Rule. Staff expects the cost will be zero as the reasonableness of the habitat mitigation fee payment will likely be more practical to operators than completing a mitigation project.

Rule 1203.c's direct impact habitat mitigation fee requirement will require CPW to dedicate habitat coordinator staff resources to determine how the mitigation is implemented on the ground in order to provide for beneficial conservation outcomes. At oil and gas locations under 11 acres, CPW Staff estimates it will spend 20 hours per location and that this will apply to 70 to 80 locations each year. This results in an annual cost between 0.750 and 0.769 FTE. At oil and gas locations over 11 acres, CPW Staff estimates it will spend 60 hours per location and that this will apply to two to four locations each year. This results in an annual cost between 0.058 and 0.115 FTE.

Finally, Rule 1203.d's requirements concerning the unavoidable adverse indirect impacts of habitat fragmentation will result in costs to CPW and Commission Staff. First, both CPW and Commission Staff assume that Staff from each agency will spend approximately two and a half hours conferring on each operator mitigation proposal. This will apply to between zero and 14 locations per year, resulting in an annual cost to CPW between 0.000 and 0.034 FTE, and an annual cost to the Commission between 0.000 and 0.034 FTE. CPW Staff also anticipates that it will spend between eight- and 60-hours monitoring how the mitigation is implemented on the ground to provide for beneficial conservation outcomes. This will apply to between zero and 14 locations per year, resulting in an annual cost to CPW between 0.000 and 0.404 FTE.

(FTE Benefit) Given that this Rule implements a new and clear directive of SB 19-181, Staff did not identify efficiencies associated with implementing Rule 1203 that would lead to an FTE benefit.

RULE(S) FOR WHICH NO COSTS OR BENEFITS ARE IMPLICATED

Of the six rules implicated by the 1200 Series, only Rule 529.d.(1), providing for CPW participation in the Commission's rulemaking stakeholder process, had no quantifiable or qualitative cost or benefit. This rule was created or amended to: comport with statutory requirements; to streamline processes; or to make other non-substantive edits. Accordingly, no measurable costs or benefits to any relevant party, either qualitative or quantitative, were determined to be present. For further explanation of Rule 529.d.(1), refer to the Statement of Basis and Purpose.

TWO ALTERNATIVES CONSIDERED IN 1200 SERIES

Staff considered a "no action" approach with respect to the requirements now found in **Rule 1203** – Compensatory Mitigation for Wildlife Resources. Staff believes that failing to include rule provisions concerning compensatory mitigation would not be fully consistent with SB 19-181's revisions to the habitat stewardship provisions in C.R.S. § 34-60-128(3)(b). Under the updated statute, the General Assembly made clear its intent that compensatory mitigation be an available option to minimize adverse direct and indirect impacts to wildlife resources.

Rule 1203 reflects Staff's goal to provide an effective mechanism to address compensatory mitigation for both direct and indirect impacts in high priority habitat areas, while also recognizing that it might be less efficient to require operators to perform these projects on their own. As detailed above, the Rule increases annual costs to industry whether a project is completed or a fee is paid. The Rule also increases costs to the Commission and CPW on an annual FTE basis. However, Staff chose to propose this Rule for one main reason: the long-term benefits to high priority habitats and associated wildlife species. Through compensatory mitigation, wildlife resources will see fewer direct and unavoidable adverse indirect impacts associated with oil and gas operations. This will lead to beneficial outcomes for high priority habitat areas and species. Therefore, the Rule as proposed will ensure that the Commission meets the mandates set forth in SB 19-181 and will provide qualitative long-term benefits to wildlife resources.

Staff also considered the alternative of setting a higher direct impact mitigation fee for locations less than 11 acres. Subpart **c** of **Rule 1203** – Compensatory Mitigation for Wildlife Resources includes a tiered approach to the direct impact mitigation fee and sets a flat fee of $13,750 at locations less than 11 acres. Staff received stakeholder feedback indicating that the proposed fee may be insufficient for CPW to both complete the mitigation necessary to account for residual adverse impacts, and ensure the long-term maintenance, monitoring, and management of the mitigation projects.

Although Staff considered these stakeholder comments, the amount of the flat fee was determined following extensive consultation and research into the resources necessary to accomplish direct impact mitigation projects at locations less than 11 acres. Under current Staff estimates, the flat fee for locations less than 11 acres is expected to yield between $1,072,500 and $1,100,000 annually for CPW to use 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. Because the fee is meant only to fund the necessary expenses incurred while performing compensatory mitigation and not as a disincentive to deter development, the Commission and CPW determined $13,750 to be an appropriate fee based on their combined experience in understanding the costs of conducting compensatory mitigation to offset the impacts to wildlife resources associated with oil and gas locations that are less than 11 acres. The fee as currently proposed will ensure that the Commission meets the mandates set forth in SB 19-181.